Natural Gas

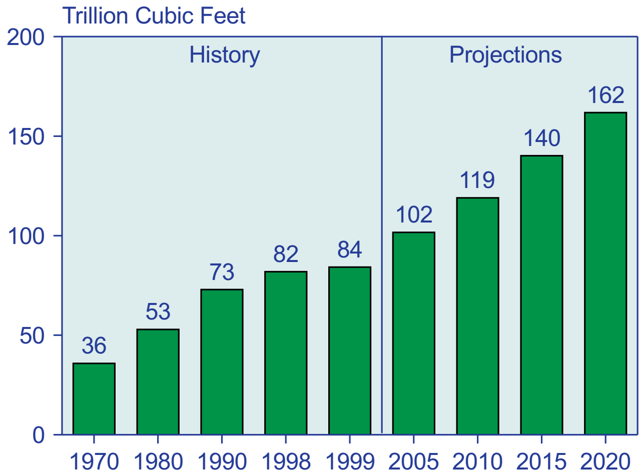
Natural gas is the fastest growing primary energy source in the IEO2002 forecast. The use of natural gas is projected to nearly double between 1999 and 2020, providing a relatively clean fuel for efficient new gas turbine power plants.

Natural gas is expected to be the fastest growing component of world energy consumption in the *International Energy Outlook 2002* (*IEO2002*) reference case. Natural gas consumption in 2020 is projected to total 162 trillion cubic feet, nearly double the 1999 total of 84 trillion cubic feet (Figure 31), and its share of total energy consumption is projected to increase from 23 percent in 1999 to 28 percent in 2020. The growth of natural gas consumption in developing countries (Figure 32) is expected to be significantly greater than in the rest of the world, averaging 5.3 percent per year, as compared with 2.4 percent per year in the industrialized countries, 2.3 percent per year in Eastern Europe and the former Soviet Union (EE/FSU), and 3.2 percent globally. In the developing countries, annual natural gas consumption is projected to almost triple over the forecast period. By comparison, nuclear electricity consumption in the developing countries is projected to grow at a rate of 4.7 percent per year, oil and coal at 3.2 percent per year, and renewable energy (primarily hydropower) at 3.0 percent per year. The largest increments in natural gas use are expected in developing Asia and North America, and the smallest increments are expected in Africa and the Middle East (Figure 33).

Much of the projected growth in natural gas consumption throughout the world is in response to rising demand for natural gas to fuel efficient new gas turbine power plants. In the *IEO2002* reference case, the projections for natural gas consumption by electricity generators show more rapid growth than the projections for any other fuel. Natural gas consumption for electricity generation is projected to grow by 4.0 percent per year in the industrialized countries, compared with -0.1 percent for oil and 0.9 percent for coal, accounting for 56.3 percent of the projected increase in total energy used to generate electricity. World gas consumption for electricity generation more than doubles in the forecast, from 27.2 trillion cubic feet in 1999 to 58.9 trillion cubic feet in 2020, and consumption in the developing countries is projected to triple, from 5.9 trillion cubic feet in 1999 to 17.7 trillion cubic feet in 2020.

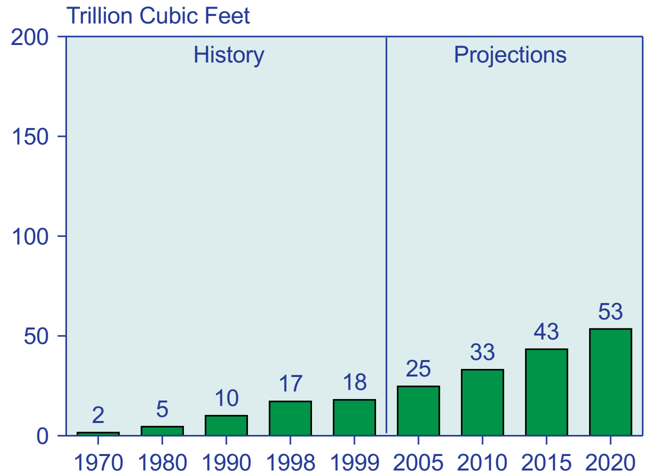
Although coal is expected to remain the predominant fuel used for power generation, natural gas is projected to capture 24 percent of the power generation market in the industrialized countries and 21 percent in the developing countries in 2020, up from 14 percent and 13 percent, respectively, in 1999. The natural gas market share

Figure 31. World Natural Gas Consumption, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Figure 32. Natural Gas Consumption in the Developing World, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

of total world energy consumption for electricity generation in 2020 is projected to be 26 percent, compared with coal's 32 percent.

The use of natural gas is increasing for a variety of reasons, including price, environmental concerns, fuel diversification and/or energy security issues, market deregulation (for both gas and electricity), and overall economic growth. In many countries, governments hold equity in natural gas companies, and this can be used as a policy instrument. Examples include Kogas (Korea), Petronas (Malaysia), Pertamina (Indonesia), China National Petroleum Corporation, Gazprom (Russia), Pemex (Mexico), Oman LNG, Adgas (subsidiary of Abu Dhabi National Oil Company), National Iranian Oil Company, Sonatrach (Algeria), Nigerian National Petroleum Corporation, Egyptian General Petroleum Company, and Mossgas in South Africa. Most of these governments are fostering the expansion of their respective natural gas markets.

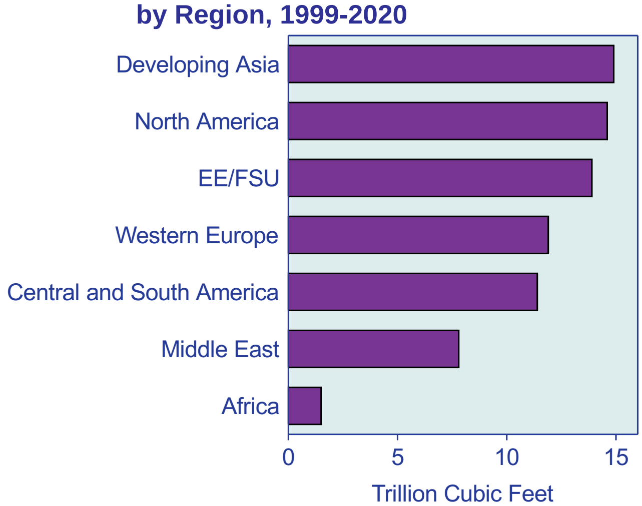
The amount of natural gas traded across international borders continues to grow, increasing from barely 20 percent of the world's consumption in 1999 to 22 percent in 2000 [*1*]. Pipeline exports grew by 8 percent and liquefied natural gas (LNG) trade grew by 10.3 percent between 1999 and 2000. Numerous international pipelines are either planned or already under construction. Projected increases in world natural gas consumption will require bringing new gas resources to market. The fact that many sources of natural gas are far from demand centers, coupled with cost decreases throughout the LNG chain, has made LNG more economical, contributing to the expectation of strong worldwide growth for LNG.

The economics of transporting natural gas to demand centers currently depend on the market price, and the pricing of natural gas is not as straightforward as the pricing of oil. More than 50 percent of the world's oil consumption is traded internationally, whereas natural gas markets tend to be more regional in nature, and prices can vary considerably from country to country. In Asia and Europe, for example, LNG markets are strongly influenced by oil and oil product markets rather than by natural gas prices. As the use and trade of natural gas continue to grow, it is expected that pricing mechanisms will continue to evolve, facilitating international trade and paving the way for a global natural gas market.

Reserves and Resources

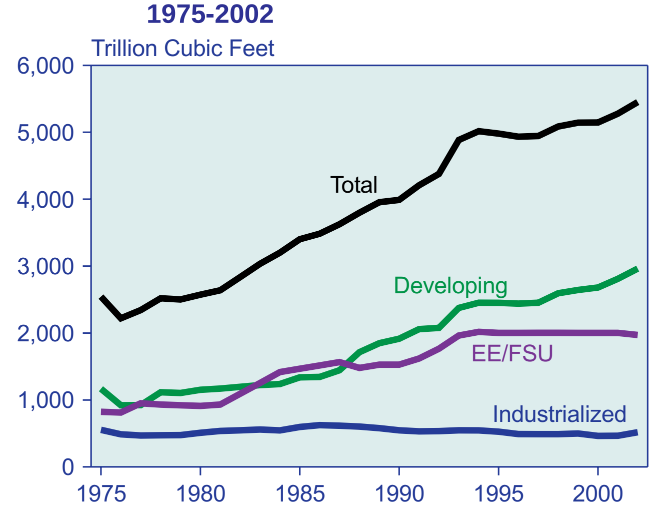
Since the mid-1970s, world natural gas reserves have in general increased each year (Figure 34). As of January 1, 2002, proved world natural gas reserves,[5] as reported by *Oil & Gas Journal*, were estimated at 5,451 trillion cubic feet, 173 trillion cubic feet more than the estimate for 2001. Most of the increase is attributed to developing countries, where gas reserves have increased by 152 trillion cubic feet since last year's survey. Natural gas reserves in the industrialized countries also increased

Figure 33. Increases in Natural Gas Consumption by Region, 1999-2020



Sources: **1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2020:** EIA, World Energy Projection System (2002).

Figure 34. World Natural Gas Reserves by Region, 1975-2002



Sources: **1975-1993:** "Worldwide Oil and Gas at a Glance," *International Petroleum Encyclopedia* (Tulsa, OK: PennWell Publishing, various issues). **1994-2002:** *Oil & Gas Journal* (various issues).

[5]Proved reserves, as reported by the *Oil & Gas Journal*, are estimated quantities that can be recovered under present technology and prices. Figures reported for Canada and the former Soviet Union, however, include reserves in the probable category. Natural gas reserves reported by the *Oil & Gas Journal* are compiled from voluntary survey responses and do not always reflect the most recent changes. Significant gas discoveries made during 2001 are not likely to be reflected in the reported reserves.

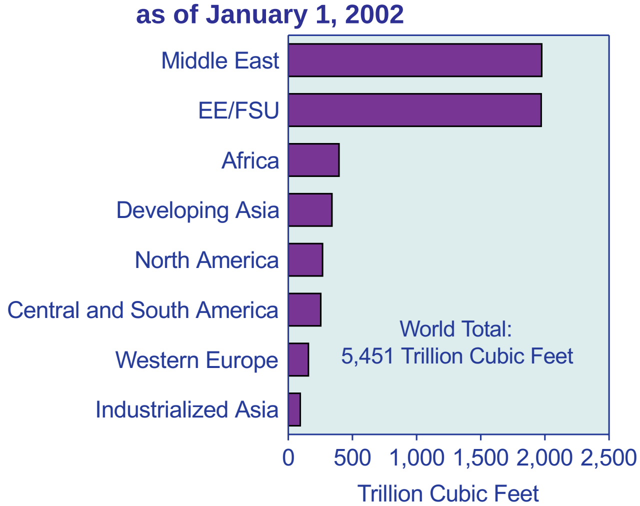
between 2001 and 2002, by 52 trillion cubic feet. EE / FSU reserves declined by 31 trillion cubic feet—mostly as a result of lowered estimates for Russia and for the East European countries Hungary and Romania, where reserves were halved over the past year.

The majority (about 72 percent) of the world's natural gas reserves are located in the Middle East and the FSU (Figure 35). Russia and Iran together account for almost one-half of the world's natural gas reserves (Table 14). Reserves in the rest of the world are fairly evenly distributed on a regional basis.

Despite high rates of increase in natural gas consumption, particularly over the past decade, most regional reserves-to-production ratios have remained high. Worldwide, the reserves-to-production ratio is estimated at 60.0 years [***2***]. Central and South America has a reserves-to-production ratio of 71.8 years, the FSU 79.6 years, and Africa 86.2 years. The Middle East's reserves-to-production ratio exceeds 100 years.

The largest expansion in natural gas reserves between 2001 and 2002 occurred in the Middle East, where 120 trillion cubic feet was added to the region's reserve base. Of that amount, 115 trillion cubic feet was attributed to revised estimates of Qatar's reserves by officials of Qatargas and Rasgas [***3***]. Developing Asia also saw an increase in reserves of 23 trillion cubic feet over the past year. Among the developing Asian countries, the greatest increase in proven reserves was in Indonesia, where reserves grew by 20 trillion cubic feet. Pakistan and Papua New Guinea, and to a lesser extent the Philippines and Thailand, also saw modest increases in gas reserves. Malaysia was the only developing Asian country with a notable decline in reserves, from 82 trillion cubic feet in 2001 to 75 trillion cubic feet in 2002.

Figure 35. World Natural Gas Reserves by Region as of January 1, 2002



Source: "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 99, No. 52 (December 24, 2001), pp. 126-127.

In the industrialized world, reserves have remained fairly stable for much of the past 20 years. In both North America and industrialized Asia, reserves increased from 2001 to 2002. In North America, an increment of 10 trillion cubic feet in U.S. natural gas reserves offset declines in Canada and Mexico. In industrialized Asia, Australia's reserves increased by 45 trillion cubic feet, more than doubling its reserve estimate from 2001.

The U.S. Geological Survey (USGS) periodically assesses the long-term production potential of worldwide petroleum resources (oil, natural gas, and natural gas liquids). According to the most recent USGS estimates, released in the *World Petroleum Assessment 2000*, a significant volume of natural gas remains to be discovered. The mean estimate for worldwide undiscovered gas is 5,196 trillion cubic feet (Figure 36), which is approximately double the worldwide cumulative consumption forecast in *IEO2002*. Reserves plus resources are four times the cumulative consumption forecast.

Of the new natural gas resources expected to be added over the next 25 years, reserve growth accounts for 3,660

Table 14. World Natural Gas Reserves by Country as of January 1, 2002

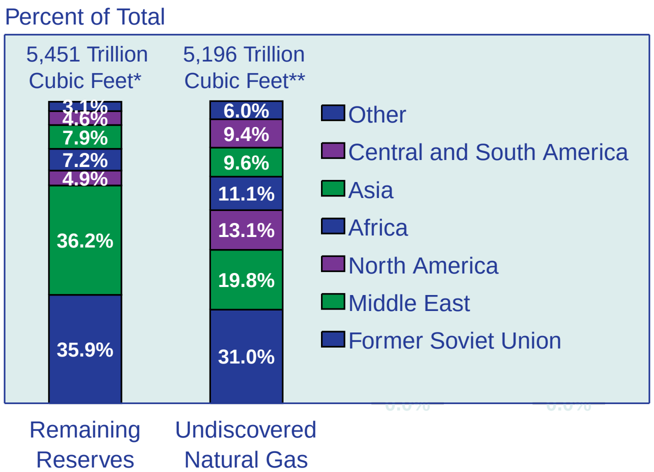
Country	Reserves (Trillion Cubic Feet)	Percent of World Total
World	**5,451**	**100.0**
Top 20 Countries	**4,863**	**89.2**
Russia	1,680	30.8
Iran	812	14.9
Qatar	509	9.3
Saudi Arabia	219	4.0
United Arab Emirates	212	3.9
United States	177	3.3
Algeria	160	2.9
Venezuela	148	2.7
Nigeria	124	2.3
Iraq	110	2.0
Turkmenistan	101	1.9
Indonesia	93	1.7
Australia	90	1.7
Malaysia	75	1.4
Uzbekistan	66	1.2
Kazakhstan	65	1.2
Netherlands	63	1.1
Canada	60	1.1
Kuwait	52	1.0
China	48	0.9
Rest of World	**588**	**10.8**

Source: "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 99, No. 52 (December 24, 2001), pp. 126-127.

trillion cubic feet. More than one-half of the mean undiscovered gas estimate is expected to come from the former Soviet Union, the Middle East, and North Africa, and an additional 1,169 trillion cubic feet is expected to come from a combination of North, Central, and South America. It is estimated that about one-fourth of the undiscovered natural gas reserves worldwide are in undiscovered oil fields.

Although the United States has produced more than 40 percent of its total estimated natural gas endowment and carries less than 10 percent as remaining reserves, in the rest of the world reserves have been largely unexploited. Outside the United States, the world has produced less than 10 percent of its total estimated natural gas endowment and carries more than 30 percent as remaining reserves.

Figure 36. World Natural Gas Resources by Region



*As of January 1, 2002. **Through 2025.

Source: U.S. Geological Survey, *World Petroleum Assessment 2000*, web site http://greenwood.cr.usgs.gov/energy/WorldEnergy/DDS-60; "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 99, No. 52 (December 24, 2001), pp. 126-127.

Regional Activity

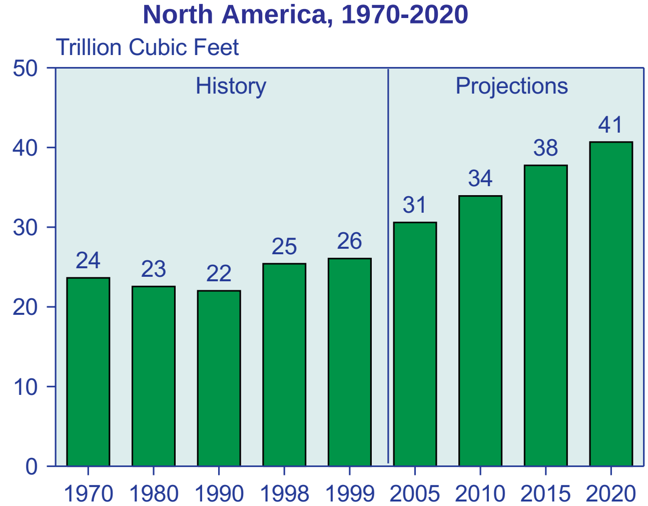
North America

Natural gas consumption in the *IEO2002* forecast for North America is projected to grow at a rate of 2.1 percent per year between 1999 and 2020 (Figure 37). Demand for gas is projected to increase in all three countries of the region (United States, Canada, and Mexico), but the most rapid growth rates are projected for Mexico, where the present immature gas infrastructure is expected to expand over the forecast period (Figure 38). The North American region is rapidly moving toward becoming an integrated gas market, and a substantial increase in the movement of natural gas between the United States, Canada, and Mexico is expected in the future.

United States and Canada

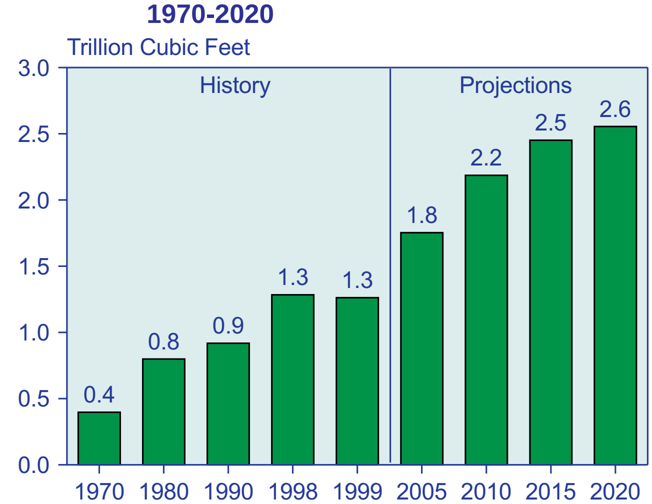
The United States currently is the dominant consumer of natural gas in North America, and it is expected to remain in that position throughout the projection period. Total U.S. natural gas consumption is projected to increase from 22 trillion cubic feet in 1999 to 34 trillion cubic feet in 2020 (compared with Canada's projected 4 trillion cubic feet in 2020 and Mexico's 3 trillion cubic feet). Much of the increment in U.S. gas use is expected in the electricity sector, where electricity generators (excluding cogenerators) are projected to account for 55

Figure 37. Natural Gas Consumption in North America, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Figure 38. Natural Gas Consumption in Mexico, 1970-2020



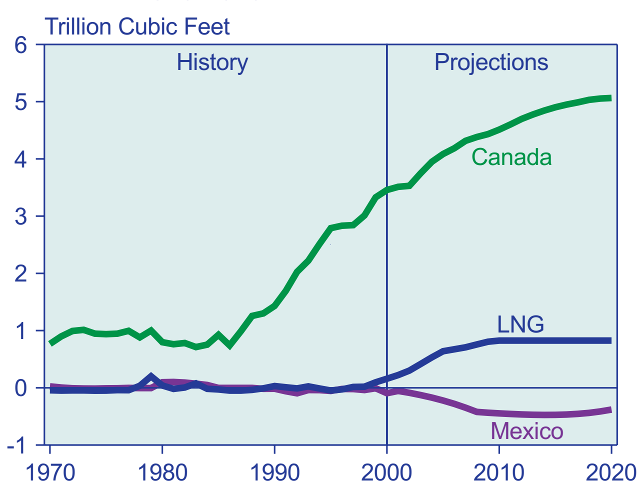
Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

percent of total U.S. natural gas consumption by 2020, according to the Energy Information Administration's *Annual Energy Outlook 2002* (*AEO2002*) [***4***]. Electricity generation is expected to surpass the industrial sector as the largest consumer of natural gas in the United States, with lower capital costs, higher fuel efficiency, shorter construction lead times, and lower emissions favoring natural-gas-fired generation over coal-fired generation.

Natural gas accounts for 25 percent of Canada's total energy consumption, and its share is not expected to change substantially over the projection period. Because the country already relies on its ample supply of cheap hydroelectric power to provide more than one-half of its electricity supply, natural-gas-fired generating capacity is not expected to expand as dramatically as in the United States. As a result, much of Canada's natural gas production is expected to be exported to the United States, where increasing demand will be greatest. Record high prices for natural gas in the United States in 2000 underscored the potential benefits to Canadian gas exporters. Canada's natural gas exports provided significant increases in revenues to producers, accounting for close to two-thirds of the country's 2000 trade surplus. It is estimated that Canadian gas revenues reached $13.8 billion, compared with estimated 1999 revenues of $7.3 billion [***5***].

As the U.S. demand for natural gas increases, the country will come to rely more heavily on imports, particularly from Canada (Figure 39). Over the past several years, the United States has experienced a widening gap between production and consumption, and in 2000 it consumed 18.0 percent more than it produced. The

Figure 39. Net U.S. Imports of Natural Gas, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001).

difference was made up with pipeline imports from Canada and Mexico and LNG imports from numerous sources, including Algeria, the United Arab Emirates, Australia, Qatar, Trinidad and Tobago, Malaysia, Nigeria, Oman, and Indonesia. Canada accounted for 93.8 percent of U.S. natural gas imports in 2000, LNG 5.9 percent, and Mexico 0.3 percent.

Imports into the United States from Canada in 2000 were 5.2 percent higher than in 1999, and during the first 9 months of 2001 they were 10 percent higher than over the same period in 2000 (2.9 trillion cubic feet vs. 2.6 trillion cubic feet) [***6***]. Over the past several years, cross-border pipeline capacity has increased considerably between the two countries. Most recently, the Alliance Pipeline was completed in December 2000, allowing 1,325 million cubic feet per day of natural gas from western Canada to be moved through North Dakota and into Chicago.

Although recent pipeline additions have provided significant increases in cross-border capacity between western Canada and the United States, there are pipeline bottlenecks within Canada that prevent some new supplies from reaching U.S. markets. There are several projects underway to alleviate this problem. Canadian Natural Resources (CNR), for example, has received approval to construct a pipeline from Ladyfern (where a discovery in 2000 is estimated to be one of the most prolific gas discoveries in western Canada in the past 15 years) in northeastern British Columbia to Northwestern Alberta, where it can then link up with TransCanada Pipeline's transcontinental network to move gas to southern Canada and the United States. The new pipeline is scheduled for completion in March 2002. It will have an initial capacity of 680 million cubic feet per day but could eventually be expanded to 1.35 billion cubic feet per day [***7***].

Another project aimed at increasing Canada's ability to export natural gas to U.S. markets is being implemented in eastern Canada. Maritimes and Northeast Pipeline plans to increase pipeline capacity to 1 billion cubic feet per day to bring in new reserves from offshore Atlantic Canada. According to Maritimes and Northeast president Phillip Knoll, the existing system can be economically expanded through compression and looping to allow producers competitive rates for getting their supplies to New England markets for new gas-fired generators [***8***].

U.S. imports of LNG are expected to quadruple over the next two decades, increasing the LNG share of gas imports to 14.7 percent in 2020. The development of an LNG market in the United States has been constrained by limitations on the amount it can receive and regasify. There are currently four LNG receiving facilities in the United States. Two have been operating for several years, one in Everett, Massachusetts, and one in Lake Charles, Louisiana. In September 2001, a facility reopened at Elba Island, Georgia, after several years of inactivity. The fourth facility is scheduled to reopen at Cove Point, Maryland, by mid-2002.

Algeria was the only source of LNG supply for the United States until May 1999, when supplies began arriving from Trinidad and Tobago. Trinidad and Tobago has now replaced Algeria as the primary source of U.S. LNG supply. Trinidad and Tobago and Algeria currently have the only long-term contract sales for LNG, but spot cargos have been imported from Qatar, Nigeria, Australia, Oman, Indonesia, and the United Arab Emirates, and spot market sales in the U.S. market continue to grow [***9***]. In the third quarter of 2001, short-term LNG imports totaled 51.3 billion cubic feet, compared with 44.7 billion cubic feet in the third quarter 2000.

As a result of the renewed interest in LNG, numerous additional facilities are being considered, including sites in the Gulf of Mexico, North Carolina, and Florida; however, siting an LNG receiving terminal in the United States can be a formidable task. Aside from the geographical requirements, the NIMBY (Not In My Back Yard) factor can be close to insurmountable and is likely to be the most important factor in whether a facility is built at a particular location. To avoid this problem, there have been proposals to site the facilities outside US borders, notably, in Baja California (Mexico) and in the Bahamas. Local opposition makes the prospect of new facilities to serve U.S. markets uncertain for the near future.

The opposition to new LNG receiving facilities does not preclude expansion at existing facilities, however. El Paso subsidiary Southern LNG has plans to expand its Elba Island facility by 80 percent, adding 360 million cubic feet per day of sendout capacity to its current 440 million cubic feet per day. The added capacity is expected to be in place by June 1, 2005 [***10***]. Talk of new facilities continues in spite of a significant drop in natural gas prices over the past year, with many developers stating that even with the current U.S. prices of under $3.00 per thousand cubic feet, they expect LNG to be economical in the future and are proceeding with their plans. The *AEO2002* forecast projects expansion of existing facilities and increases in gross LNG imports averaging 7.1 percent per year, from 220 billion cubic feet in 2000 to 890 billion cubic feet in 2020.

Mexico

In Mexico, natural gas consumption has been growing, but production has been falling. Mexico's consumption of natural gas is projected to increase by 3.4 percent per year between 1999 and 2020, with much of the increase in the industrial sector and for new electricity generation. As a result of the widening gap between production and consumption, Mexico has had to increase imports, and its import capacity is also being expanded with an eye to the future. In October 2000, the bidirectional Coral Energy pipeline between Mexico and the border near McAllen, Texas, became operational (300 million cubic feet per day). Exports from the United States to Mexico increased by 72 percent between 1999 and 2000 and by 24 percent between the first 9 months of 2000 and the first 9 months of 2001 (98 billion cubic feet vs. 79 billion cubic feet) [***11***]. In addition, Tidelands Oil and Gas, based in Texas, has filed for approval to build three 6-mile pipelines from Eagle Pass in Texas to Piedras Negras in Mexico, which would supplement the current capacity at nine existing border crossings [***12***].

El Paso Natural Gas has filed to increase its capacity at the Mexican border from 208 million cubic feet per day to 308 million cubic feet per day [***13***]. According to El Paso, the increase is to meet Mexico's need for 60 million cubic per day of natural gas initially to fuel the new Chihuahua II power plant in El Encino and an additional 40 million cubic feet per day for a new turbine generator to be installed in February 2002. El Paso plans to add the capacity by increasing compression along the existing Samalayuca Lateral. Another major incentive for increased capacity between the United States and Mexico, according to El Paso, is the rapid development of northern Mexico's pipeline infrastructure [***14***].

In addition to pipeline imports, LNG is expected to meet some of Mexico's growing demand, and several LNG receiving facilities have been proposed to serve markets in northwestern Mexico and southern California. Sempra Energy and CMS Energy have proposed a joint venture for a terminal north of Ensenada in Mexico's Baja California with a sendout capacity of 1 billion cubic feet per day; Phillips Petroleum and El Paso Corporation have proposed a 630 million cubic feet per day facility; El Paso is also considering a terminal to be located offshore California; and Chevron is evaluating both offshore California and Baja California for a 750 million cubic feet per day facility [***15***]. Shell Oil, in partnership with El Paso, is planning a 0.5 to 1.0 billion cubic feet per day receiving facility in Mexico's east coast Tamaulipas state at Altamira that would receive gas from Africa, the Carribean, and South America. Turning towards South America, Mexico has had preliminary talks outlining an economic agreement with Bolivia that would allow the Pacific LNG consortium (Respol-YPF, British Gas, and British Petroleum), to use Mexico's pipelines and plants to process LNG from Bolivia to be exported to the United States for use in southern California [***16***]. The arrangement would also provide Mexico with Bolivian gas for its own use.

Mexico is also struggling to restructure its natural gas industry in order to develop its vast natural gas resources. Two factors that hinder more rapid expansion of the gas market in Mexico are the complete control of the exploration and production sector of the market by Petroleos Mexicanos (Pemex), the state oil and gas company, and the lack of infrastructure to move gas from the main producing areas in the south to the major consuming regions in the north. While the distribution segment of the industry has been open to private investment since 1995 and has seen significant growth in recent years, exploration and production continue to be controlled by Pemex.

The Mexican government feels it is imperative that progress be made in opening the natural gas production sector, because the government does not have the financial resources to fully develop the country's reserves. To this end, Pemex is working to develop a multiple-service contract that can be used to get foreign investors to help develop Mexico's natural gas. According to Dominguez Vargas, first vice-president of technology and professional development for Pemex, the initial emphasis would be on getting contracts in place for development efforts in the Burgos basin in northeastern Mexico, where the largest production increase could be achieved [***17***].

The situation is a difficult one for Mexican President Vicente Fox, who took office on December 1, 2000. Most of Mexico's current natural gas production is associated with light crude oil production, and the declining ratio of light crude to total crude production yields a corresponding decline in associated gas production [***18***]. According to Energy Minister Ernesto Martens, Mexico will need to increase its gas production from the current 5 billion cubic feet per day to 12 billion cubic feet per day by 2006 [***19***]. The Fox administration favors restructuring Mexico's energy markets, but it will be difficult to implement any sweeping reform, because the party lacks a majority in both of the Mexican government's legislative bodies. At a minimum, Fox has indicated that he intends to open up exploration and development of nonassociated gas to private investment.

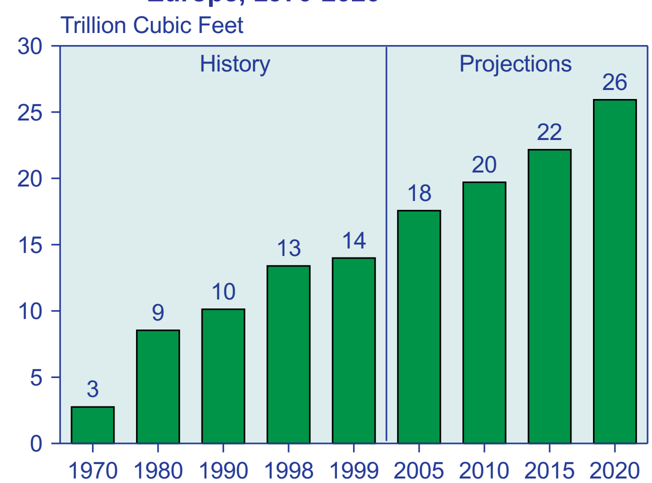
Western Europe

Natural gas is the fastest growing fuel source in Western Europe, despite the region's limited natural gas resources. The region accounts for less than 5 percent of the world's natural gas reserves but in 1999 consumed 17 percent of the world total. Over the next two decades, natural gas consumption in Western Europe is projected to grow at an average annual rate of 3.0 percent in the *IEO2002* reference case forecast, compared with a rate of 1.0 percent for total primary energy consumption (Figure 40). In addition to a preference for natural gas over coal for environmental reasons, Europe's natural gas use is growing due to readily available supplies to supplement domestic production coming by pipeline from the FSU and Algeria, and by tanker in the form of LNG from a number of sources. Recent demand increases reflect rising gas use for power generation and for the industrial sector. Consumption of natural gas for electricity generation is projected to more than double over the projection period.

The European Union (EU) has played an important role in the development of Western Europe's natural gas markets, passing key legislation over the past several years to liberalize both the electricity and natural gas markets of its member countries. The EU Directive on Electricity was passed in January 1997, opening up electricity markets in member nations to competition within 2 years, and its Natural Gas Directive was passed in June 1998 requiring the opening of gas markets.

The objective of the Natural Gas Directive is to ensure the free movement of natural gas and improve security of supply and industrial competitiveness. It established common rules for the EU's internal natural gas market regarding the storage, transmission, supply, and distribution of natural gas. The rules addressed market access, criteria and procedures for systems operations, and the granting of licences for natural gas supply, transmission, storage, and distribution. The Directive set a deadline of August 10, 2000, for members (with the exception of emerging markets in Portugal and Greece) to have arrangements in place for third-party access to gas infrastructure. By that date all gas-fired power generators and customers using more than 883 million cubic feet of natural gas per year were to be eligible to choose a

Figure 40. Natural Gas Consumption in Western Europe, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

gas supplier. Customers using at least 530 million cubic feet per year are to be eligible by 2003, and those using at least 177 million cubic feet per year are to be eligible by 2008.

In May 1999 a report by the European Commission (a branch of the EU) was released, calling for the acceleration of the gas market liberalization from 2008 to January 2005 at the latest [***20***, ***21***]. Subsequently, on March 13, 2001, the Commission outlined the current state of progress, recommending the following measures to achieve the accelerated gas market objective:

- Adoption of appropriate rules with respect to the pricing of cross-border trade
- Adoption of rules for allocation and management of interconnection capacity
- Where economically justified, increasing existing physical interconnection capacity.

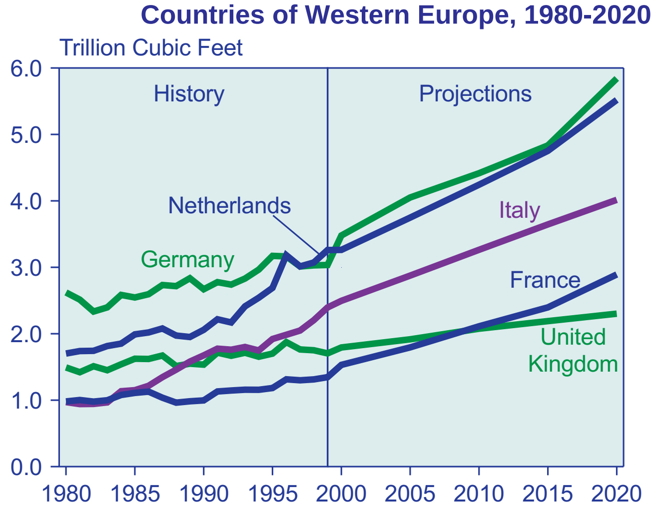
The largest consumers in Western Europe by far are the United Kingdom, Germany, Italy, the Netherlands, and France, and consumption in these countries is expected to grow steadily over the forecast period (Figure 41). More than one-half of the region's resources are concentrated in the United Kingdom, the Netherlands, and Norway, which are the region's primary producers. Almost all Western European gas production is consumed internally, with the exception of small quantities exported by France, Germany, and Norway to Eastern European markets.

Although the projected incremental increases in consumption are far less than those in the largest consuming countries, some of the most rapid growth rates in natural gas consumption in Western Europe are occurring in countries where natural gas markets are just beginning to flourish—including Portugal, Greece, Ireland, and Spain (Figure 42). Portugal and Greece are two of the smallest economies represented in the EU and are considered by the EU to be emerging gas markets, a status that gives them flexibility in meeting the deadlines of the Natural Gas Directive for opening their gas markets. Both countries consumed less than 10 billion cubic feet per year before 1998, when consumption in Portugal jumped to 28 billion cubic feet and in Greece to 30 billion cubic feet. Consumption in both countries rose dramatically again in 1999, to 80 and 53 billion cubic feet, and the growth is continuing. Natural gas markets in Ireland and Spain have been developing for a longer period, and recent consumption increases, while not as impressive, are nonetheless significant.

Portugal

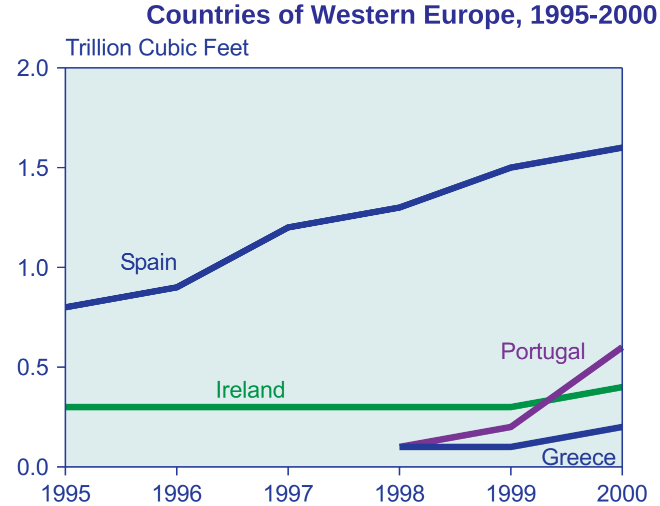
In Portugal, the natural gas market is less than 5 years old. There was no measurable consumption until 1997, when the Maghreb-Europe pipeline connected the Iberian peninsula to Algerian gas sources (via Morocco). Since then, gas use has risen steadily. Although virtually all of Portugal's natural gas still comes by pipeline from Algeria, it also began importing LNG in 1998 and in 1999 entered into a contract to purchase LNG from Nigeria for 20 years beginning in 2002. The LNG will be regasified initially in Spain and piped into Portugal until a terminal under construction at Sines, Portugal, scheduled to become operational in 2003, is completed. The Sines terminal will have a capacity of 580 billion cubic feet per year and will be operated by Transgas.

Figure 41. Natural Gas Consumption in Five Countries of Western Europe, 1980-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Figure 42. Natural Gas Consumption in Four Countries of Western Europe, 1995-2000



Source: Energy Information Administration, *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001).

Almost all of the natural gas consumption in Portugal is to fuel electricity generation. A member of the EU, Portugal has received EU assistance in investment in its gas infrastructure. Approximately $417 million (485 million euros) was spent on improving Portugal's infrastructure between 1994 and 1999, when the EU decided to cut back on spending. Nevertheless, there are still plans to expand the network from 3,761 miles in 1999 to 5,943 miles in 2010 [***22***]. Under the EU Gas Directive, as an emerging natural gas market Portugal is not required to open its domestic gas market to full competition until 2008. It was, however, required to open at least 33 percent of its market to competition by 2001—a target that still has not been met. As a result, the EU has begun infringement procedures.

Greece

In Greece, the government historically has maintained a prominent role in the energy industry, and the natural gas market remains under the control of the state-owned Greek Public Gas Company (DEPA). DEPA was established in 1988 to promote natural gas use in order to diversify Greece's energy sources, but the market actually declined until 1997 when the government loosened its control on the industry and allowed foreign participation. Since that time, rapid expansion has been occurring.

A member of the EU, Greece has taken full advantage of all the EU waivers its emerging market status allows in order to delay EU-mandated energy sector privatization, and it is only recently that privatization has made any inroads. Under agreements signed in July 2001, a new distribution company, EDA Attikis, 51 percent of which is owned by DEPA and the remainder by Cinergy of the United States and Royal Dutch / Shell, will supply Athens and its surrounding areas with natural gas, covering 30 percent of Greece's population. Although Athens was the first Greek city to have a gas distribution network, at present only about 8,000 customers are connected to the network in a city of more than 3.1 million [***23***]. EDA Attikis plans to expand the network to reach 55 percent of the region's population and expects demand to reach about 35 billion cubic feet by 2020. In 2000, the Italian utility company, Italgas (a subsidiary of ENI), won 30-year concessions to build and operate two city gas distribution networks, in Thessaloniki and Thessaly; and it will have a minority stake in the network ownership and management of each. DEPA has the exclusive contract to supply the three distribution networks for 15 years [***24***].

Greece intends to diversify its import sources, and in July 2000 it agreed to work with Turkey to develop connections between their natural gas networks. The two countries have agreed to work with the EU-sponsored Interstate Oil Gas Transport to Europe (INOGATE) project, which provides technical assistance to modernize oil and gas transport in central Europe and Asia in order to work toward European pipeline linkages to Caucasus and Asian oil and gas.

In March 2001, Greece signed an agreement with Armenia and Iran to strengthen economic and energy cooperation. Discussions included the possibility of an EU-subsidized natural gas pipeline from Iran through either Armenia and Ukraine or Turkey and Greece to other European customers. LNG is also a source of imports for Greece. The country began importing LNG from Algeria in late 1999 into its LNG terminal at Revithoussa, near Athens. The terminal is small, with a receiving capacity of 23 billion cubic feet per year. It is possible that the terminal could be expanded, or that an additional terminal could be built: however, an undersea natural gas pipeline from Italy to Greece is currently in the feasibility study phase [***25***], and if that project is approved it could reduce the impetus to expand LNG markets in Greece.

Ireland

In Ireland, switching to natural gas is seen as a way to reduce carbon dioxide emissions from electricity generation. According to the Ireland Department of Public Enterprise, close to half of Ireland's natural gas consumption is currently for electricity generation, and its share is expected to continue to increase [***26***]. There is also a strong move to continue the expansion of the residential and small commercial / industrial markets that have been growing as the distribution infrastructure expands. Phoenix Natural Gas, in particular, is currently focusing on this market.

At present, Ireland's only indigenous source of natural gas is the Kinsale Head Gas Field, which has been producing since 1978. The field is now in decline and is expected to be depleted by 2004. Dependence on imports is thus climbing as gas use accelerates. In 2000, one-half of Ireland's consumption of 134 billion cubic feet was imported from the United Kingdom. Kinsale production is likely to be supplemented in 2002 with supplies from the Corrib Gas Field, a recently discovered field off Ireland's northwest coast.

Natural gas imports to Ireland were first made possible by the completion of the 180-mile Interconnector from Scotland, with a capacity of 194 billion cubic feet per year [***27***]. Expansion of the country's pipeline transmission infrastructure is currently underway. The Celtic Energy consortium is planning to construct a pipeline linking North Dublin to Wales and England, scheduled for completion by the end of 2002, and the Premier Transco group is assessing the possibility of a pipeline linking Belfast and Dublin. Bord Gais Eireann has submitted an application to construct three natural gas transmission pipelines: (1) to the west, from Dublin to Limerick to Galway Ringmain; (2) from Mayo to Galway; and (3) a second Scotland to Ireland Interconnector.

Spain

Strong growth in natural gas use is occurring in Spain as the country phases out its older nuclear and coal power plants in favor of gas. Estimates are that Spain could easily double its gas consumption by 2010 [***28***]. Spain is almost entirely dependent on imports to satisfy its gas demand, and that situation is not expected to change in the foreseeable future. The country's domestic resources are limited: its one major gas field ceased production in 1995, and there have been no new discoveries since then. In 2000, Spain imported half of the gas it consumed by pipeline from Norway and Algeria (primarily Algeria).

The remaining half of Spain's natural gas comes in the form of LNG. It is imported from a number of countries, including (in order of magnitude) Algeria, Nigeria, Libya, Trinidad and Tobago, Qatar, United Arab Emirates, Malaysia, and Oman. In fact, Spain is one of Europe's largest importers of LNG, second only to France. Spain currently has three LNG receiving terminals, all operated by Enagas, located in Barcelona, Huelva, and Cartagena. The three terminals, with a combined capacity of 500 billion cubic feet per year, became operational in 1969, 1988, and 1999. There is also considerable growth in LNG receiving capacity on the horizon, with two new terminals currently under construction and a third in the planning stage. The first of those under construction is scheduled to come online in 2003 in the port of Bilboa in the northern Basque region and be operated by Bahia de Bizkaia Gas. The second is expected to come online in 2005 in Valencia and be operated by Union Fenosa. The proposed terminal, to be located in Murgardos, will be operated by Union Fenosa, Endesa, and Sonartrach, in addition to local companies [***29***].

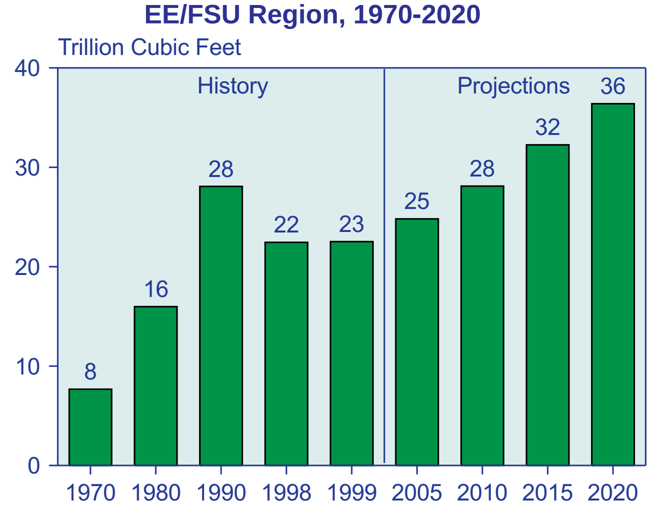
Eastern Europe and the Former Soviet Union

With 2,003 trillion cubic feet of proven natural gas reserves, the FSU accounts for 38 percent of the world total. Russia lays claim to 85 percent of those reserves, making it the largest potential source of natural gas in the world. Reserves in Iran, which is second to Russia, amount to less than one-half of Russia's total. Other gas producing countries in the FSU include Turkmenistan, Uzbekistan, Ukraine, and Kazakhstan. Of the four, Turkmenistan contains just over 100 trillion cubic feet of reserves, accounting for almost 2 percent of the world's total reserves, and the others each account for around 1 percent of the world's total.

Unstable political and economic conditions in the early to mid-1990s led to significant declines in EE / FSU natural gas markets. Between 1990 and 1998, consumption declined by more than 20 percent. Although the declining trend has been reversed, the region still falls far short of both the production and consumption levels realized in 1990. Gas markets in the EE / FSU continue to face a number of complex issues, including curtailments, nonpayment, declining Russian production, transit disputes, and economic and political conditions that have not been conducive to foreign investment. Restructuring of gas markets is occurring, however, and the prospects for natural gas market growth in the EE / FSU look promising. The *IEO2002* forecast is for increased growth, with consumption increasing at an average annual rate of 2.3 percent over the forecast period, from 23 trillion cubic feet in 1999 to 36 trillion cubic feet in 2020 (Figure 43). Growth in Eastern Europe is expected to far outpace growth in the FSU, with Eastern European consumption projected to grow at an average annual rate of 4.7 percent, compared with the FSU's 1.9 percent. This may be explained by the fact that most East European countries have enjoyed sustained economic recovery since the early 1990s, giving them a head start over the former Soviet Republics, which have only recently begun to see positive economic growth.

Natural gas production in Russia declined by 1.1 percent in 2000, and Russia fell behind the United States to become the world's second rather than top natural gas producer for the first time in a decade. Russia consumed 69 percent of its own production, exporting the balance. Russia is the world's largest exporter of natural gas (Figure 44), supplying Europe with about 30 percent of its gas supplies. Russia's biggest European export markets are Germany, Italy, and France, each relying on Russia for more than one-third of its natural gas. Most

Figure 43. Natural Gas Consumption in the EE/FSU Region, 1970-2020



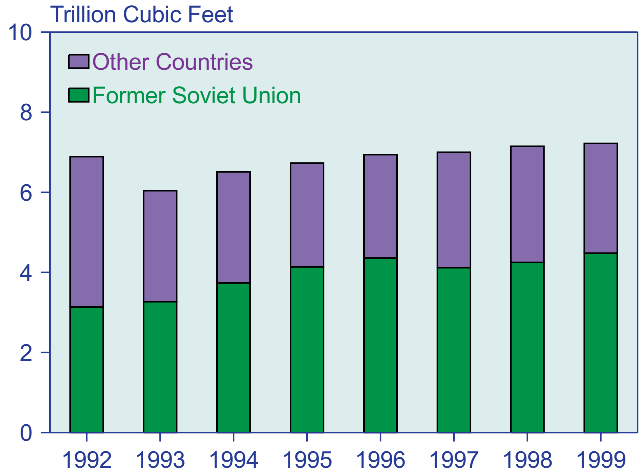
Source: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

EE/FSU countries continue to depend almost solely on Russia for their natural gas supplies. Russia has also begun to supply many of its customers, including Austria, Finland, Greece, Hungary, and Turkey, with well over half the natural gas they consume.

Russia has an extensive network of domestic pipelines as well as international pipelines linking it to export markets. Three pipelines, the Brotherhood (*Bratsvo*), Progress, and Union (*Soyuz*), deliver gas to Europe via Ukraine. A fourth pipeline, the Yamal, transits Belarus to reach European markets. A fifth, the Northern Lights, transits both Belarus and Ukraine en route to Europe. Gas markets in Finland are served by the Volga/Urals-Vyborg pipeline. A new pipeline slated to serve markets in Turkey via the Black Sea, the Blue Stream Pipeline, is currently under construction. Work began in February 2000, and Gazprom has completed the aboveground section of the pipeline from Russian territory to the Black Sea coast at Tuapse. Turkey has completed its segment of the line, from Ankara to the Black Sea coast at Samsun. The final segment will run beneath the Black Sea, connecting the Russian and Turkish sections of the project. Laying of the underwater segment began in August 2001, with completion scheduled for 2002 [***30***].

Russia hopes to both further expand its export capacity (Figure 45) and at the same time diversify its export markets so that it can ship less gas to debtor nations, such as Ukraine, and be less dependent on Ukraine as an export route. Ukraine currently serves as a transit route for more than 90 percent of Russia's exports to Europe. Problems between Russia and Ukraine continue, with Ukraine failing to keep current in its payments for gas imported from Russia, and Russia accusing Ukraine of siphoning gas it is not entitled to during transit, thus threatening Russia's European customers with natural gas shortages.

Figure 44. Russia's Net Natural Gas Exports, 1992-1999



Source: PlanEcon, *Energy Report*, Vol. 10, No. 1 (Washington, DC, May 2000), p. 38.

Figure 45. Proposed Natural Gas Export Pipelines from Russia

Source: P. Trafalgar, "Boom for Russia's Gas-Export Pipelines," *The Russia Journal* (November 23-29, 2001), p. 6

Russia plans to build the Yamal-Europe II pipeline, which would allow it to bypass Ukraine and, instead, transit Belarus, Poland, and Slovakia. A feasibility study is underway. One glitch is Poland's hesitancy to make a move that might damage the interests of Ukraine, because Ukraine is one of Poland's strategic allies. While Russia hopes to diversify its customer base, its customers have in turn attempted to reduce their dependence on Russia as a primary supplier, especially given the economic instability in Russia in the past. In order to diversify, Russia is exploring the possibility of exporting gas from eastern Siberia and / or Irkutsk to Asian markets, notably China, and several pipeline options are being considered. Gazprom has also undertaken a feasibility study on a pipeline, North TransGas, that would carry Russian gas across the Baltic Sea to serve Scandinavia and Germany. Firms developing the Sakhalin I field have proposed a pipeline to deliver Sakhalin gas to northern Japan and later Tokyo, and a feasibility study is being conducted [***31***].

Although Russian production declined in 2000, the FSU as a whole increased production by 2.7 percent, with production in Turkmenistan more than doubling and production in Kazakstan growing by 15.6 percent. Much of the increased production in Turkmenistan was exported, primarily to other EE / FSU countries but also to Iran. At present, Turkmenistan is Iran's only source of imports. Turkmenistan is the only former Soviet Republic except Russia that is exporting substantial volumes of natural gas. The country produces about 70 percent more gas than it currently consumes. Approximately 85 percent of the excess production is exported to Iran for use in Iran's non-producing northern areas, with the remaining 15 percent going to other EE / FSU countries. This is almost the reverse of the situation in 1999, when 30 percent of Turkmenistan's exports went to Iran and 70 percent to other EE / FSU countries.

Central and South America

Natural gas markets in Central and South America are relatively small, but they are growing rapidly, with considerable upstream and downstream development. *IEO2002* projects that gas consumption in Central and South America will grow to 14.6 trillion cubic feet by 2020, at an average annual growth rate of 7.4 percent (Figure 46).

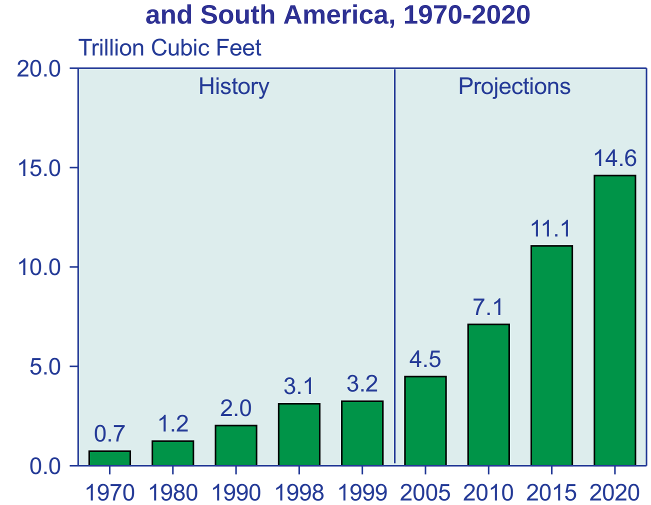
Because much of Central and South America has not yet been explored for gas, there is strong potential for new discoveries. Recent exploration activity has yielded promising discoveries, and the region's reserves have increased from 244 trillion cubic feet in 1999 to 253 trillion cubic feet in 2001. The highest concentrations of reserves are in Argentina and Bolivia in the Southern Cone Common Market, also referred to as Mercosur, and Venezuela and Trinidad and Tobago in the north.

Brazil

Consumption in Brazil has increased steadily over the past decade and is expected to grow at an average annual rate of 13.3 percent over the forecast period. Brazil is making an effort to diversify fuel use in its electricity generation sector, which is almost entirely dependent on hydropower. The country is currently experiencing an electricity shortage brought on by several years of below average rainfall that has left reservoirs less than 30 percent full and, in 2001, led the government to mandate that industrial and residential consumers reduce their electricity consumption by 20 percent. The energy crisis has added more urgency to plans for constructing substantial natural-gas-fired electricity generators. The Brazilian government is pressing to get 15 gas-fired power plants with a combined capacity of 6,423 megawatts operational by 2003 and has set a long-term goal of completing 55 new gas-fired generators before 2007 with a combined capacity of 23,000 megawatts [***32***] (see box on page 118). In an effort to promote natural gas use, plans are underway to privatize parts of the country's gas sector. Natural gas exploration and production historically have been controlled by the state company, Petrobrás, with distribution handled at the state level [***33***].

There are several pipeline projects available to serve the Brazilian markets, and several more are planned (Figure 47). One pipeline in operation connects Paraná, Argentina, to Uruguaiana, Brazil. It has been providing gas to a power plant in Uruguaiana since July 2000. An extension of the pipeline to Porto Alegre, Brazil, is currently under construction, with a targeted completion date of 2002.

Figure 46. Natural Gas Consumption in Central and South America, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

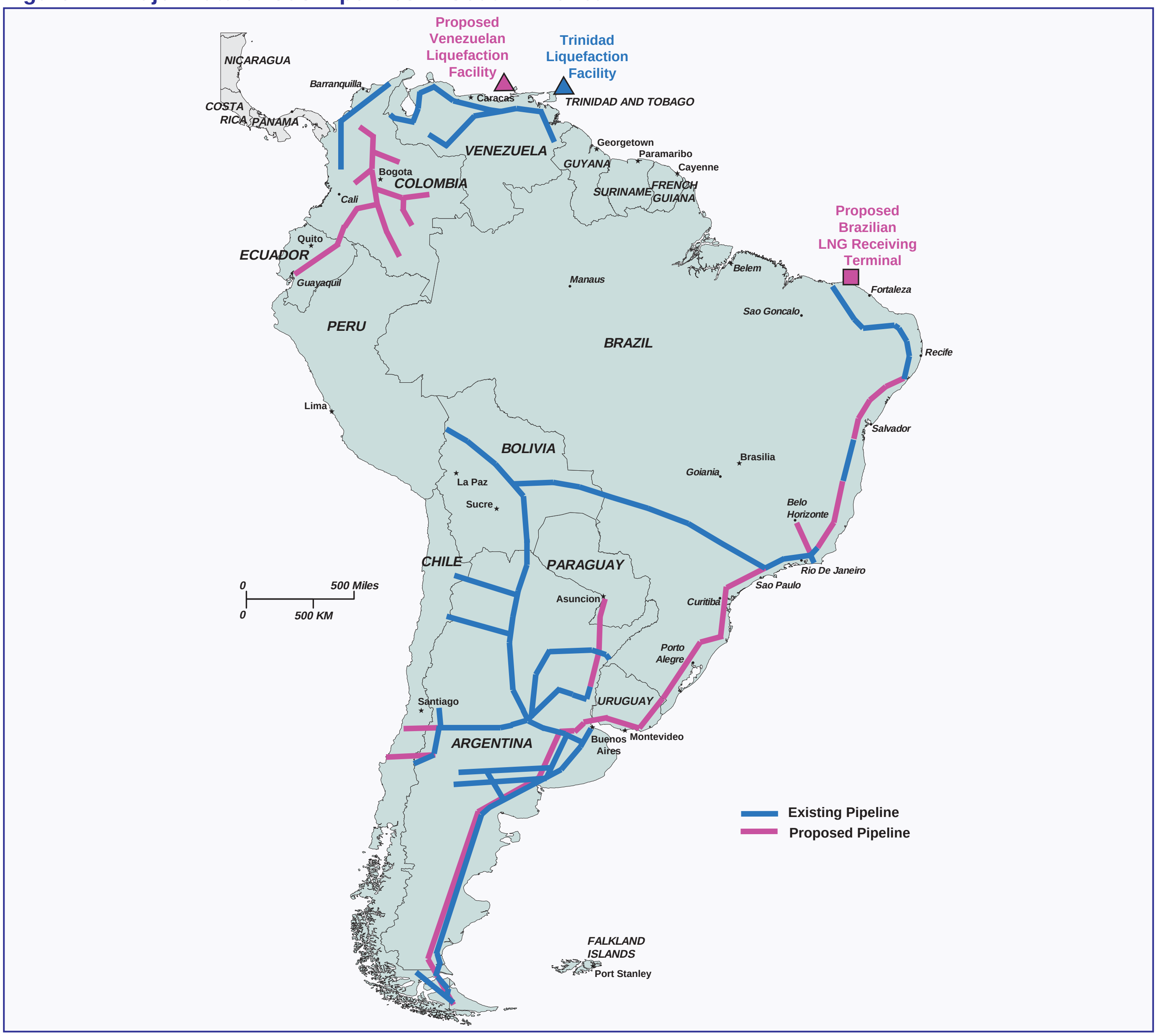
Additional Argentina-Brazil pipelines are in various stages of the planning process, although recent natural gas discoveries in Bolivia and potential Brazilian discoveries could prevent development of these pipeline projects. The potential Argentina-Brazil pipelines include the Cruz del Sur, Trans-Iguacu, and Mercosur pipelines. The Cruz del Sur would extend to Brazil an Argentine-Uruguayan pipeline that currently is under construction (construction began in March 2001, with the first deliveries slated for early 2002). The Trans-Iguacu pipeline would cross from northern Argentina's Noroeste basin into southern Brazil. The Mercosur pipeline would tap northwestern Argentina's Neuquén basin to Curitiba, Brazil, and could extend to Sao Paulo [***34***].

Other Central and South America

With new natural gas fields being discovered and developed in Bolivia and the completion of the Bolivia-Brazil pipeline, Bolivia is poised to become a major participant in the South American natural gas market. Bolivia has plans for considerable expansion of its pipeline infrastructure that will allow the country to supply gas to new natural-gas-fired electricity generators in surrounding countries, and discussions with Mexico raise the possibility that Bolivia could become an exporter of LNG.

Argentina is both South America's largest producer and consumer of natural gas, but it has been in a recession for the past 4 years and now is in the throes of a full

Figure 47. Major Natural Gas Pipelines in South America



Source: "Gas and Power in Latin America," *Oil & Gas Journal*, Vol. 99, No. 42 (October 15, 2001), p. 74.

economic crisis. Argentina has enormous debt that it cannot repay, and on January 6, 2002, the government announced a 29-percent currency devaluation. Before the devaluation, the government placed a cap on bank withdrawals that angered the citizenry, leading to protests and encouraging many to flee the country. Because Argentina has already defaulted on part of its $141 billion debt, it has in effect been cut off from international capital markets, and the International Monetary Fund (IMF) froze aid to Argentina in December 2001 [***35***]. Argentina's natural gas industry is entirely in the hands of the private sector and is operated within a competitive market structure. The economic crisis will certainly affect energy markets, most likely throughout South America, but the extent of the impact remains to be seen.

Chile is Argentina's largest export customer. Four pipelines currently connect the Argentine Neuquén basin with Chile, and there are plans to extend the GasAndes pipeline in central Chile, which has been in operation since 1997, to Rancagua, Chile, by the summer of 2002. In November 1999 the Gasoducto del Pacifico opened, transporting Argentine gas to industrial consumers in southern Chile's Bio Bio region. The other two Argentine-Chilean pipelines, the GasAtacama and the NorAndino, run parallel to each other and, along with Gasoducto del Pacifico, supply markets that do not yet fully utilize their capacities. The GasAtacama pipeline came online in July 1999 and primarily serves the Nopel power plant. The NorAndino pipeline came online in November 1999 and supplies two power plants.

Like Brazil, Chile's expected increase in natural gas consumption is fueled in part by a desire to become less dependent on hydropower, which is currently its largest source of electricity. Chile experienced rolling blackouts from late 1997 until well into 1999 as a result of drought [***36***]. Colombia saw less expansion of its natural gas sector in 2000 than did Brazil and Chile, but the government plans to foster future expansion in an attempt, like Brazil and Chile, to make its electricity sector less vulnerable to droughts. In early 2001, the Colombian congress was considering legislation to deregulate natural gas prices by 2003, to increase natural gas production for both domestic consumption and exports, and to support increased domestic consumption of natural gas, especially for electricity, was under consideration [***37***].

In the northern portion of South America, an active LNG market is developing. Atlantic LNG's Point Fortin facility, located in Trinidad and Tobago, became operational in 1999 with its first train of 3 million metric tons per year,[6] exporting 51 billion cubic feet to the United States and 25 billion cubic feet to Spain by the year's end. Trains 2 and 3 are under construction and will add 3.3 million metric tons per year each by the fourth quarter of 2002 and third quarter of 2003, respectively. When completed, the expansion will triple Atlantic's LNG export capacity. Venezuela is planning to enter the LNG market with two single-train facilities of 2.1 and 4.0 million metric tons annual export capacity scheduled for completion in 2004 and 2005, respectively. Petroleos de Venezuela (PDVSA), the state oil and gas company, is a partner in both terminals. In addition to its major clients, Trinidad and Tobago is currently supplying gas to the EcoElectrica facility in Puerto Rico and has also signed an agreement to send LNG to a new import terminal in the Dominican Republic as early as late 2002. This highlights the potential for increased use of imported LNG in smaller markets.

Industrialized Asia

Natural gas consumption in industrialized Asia (Australia, New Zealand, and Japan) is projected to increase by 1.9 percent per year from 1999 to 2020, much slower than the 11.2-percent annual average increase from 1970 to 1999. Industrialized Asia contributed 7 percent of the increase in world gas consumption over the past 3 decades, but its contribution over the next 2 decades is expected to fall to 2 percent.

Australia

An expanding pipeline system and continuing deregulation are moving Australia toward a more competitive domestic natural gas market. Deregulation of the gas market is being done by the states rather than central authorities, resulting in a piecemeal approach that has been blamed for the slow pace and wide variations in the domestic gas market. Reform for free and fair trade in natural gas was agreed to by the Commonwealth and all states and territories in 1997 but has yet to be fully implemented [***38***]. Gas consumption in Australia and New Zealand is projected to increase by 2.3 percent per year from 1999 to 2020 (Figure 48).

New and planned pipelines are starting to turn the once separate supply systems into a national grid (Figure 49). The creation of competing sources of supply has the potential to change the structure of the gas markets. One such project, a 3,200-kilometer pipeline from Papua New Guinea down the east coast to Brisbane, could eventually supply gas to markets in New South Wales and Victoria [***39***]; however, the project continues to languish despite the new leadership of ExxonMobil [***40***].

Australia's natural gas supply capability is expected to expand at a faster pace than domestic consumption, providing opportunities for additional exports. A fourth train is planned for the Northwest Shelf LNG venture. Sales and purchase agreements were signed with two Japanese utilities for LNG deliveries starting in mid-2004 [***41***]. A methanol plant and a gas-to-liquids (GTL)

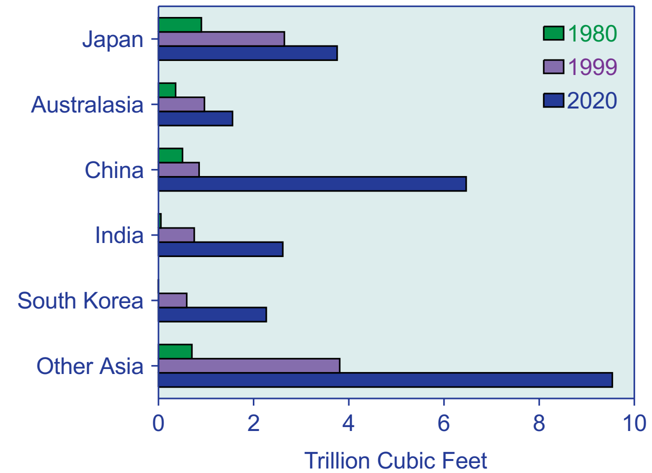
[6] A metric ton is equivalent to 48,700 cubic feet of natural gas.

facility are also being considered for the Northwest Shelf. Officials point out that the Northwest Shelf has ample gas to supply domestic as well as export projects [***42***].

Royal Dutch / Shell appears to have convinced its partners in the Greater Sunrise LNG project to develop a floating LNG facility rather than build a pipeline and a conventional onshore liquefaction plant near Darwin. Equity issues still have to be worked out, and agreements with buyers need to be secured. Greater Sunrise lies predominantly in the Australian part of the Timor Sea, but buyers remain wary because tax disputes with East Timor have halted progress on the adjacent Bayu-Undan project. Shell believes that the floating facility will be up to 40 percent cheaper than the onshore option [***43***].

The development of the 9.6 trillion cubic feet of untapped gas reserves in the Gorgon fields remains uncertain. The Gorgon partners have been trying for years to decide between an independent project and integrating their resources with the Northwest Shelf. The Northwest Shelf consortium currently believes that they can honor all contracts without the Gorgon reserves

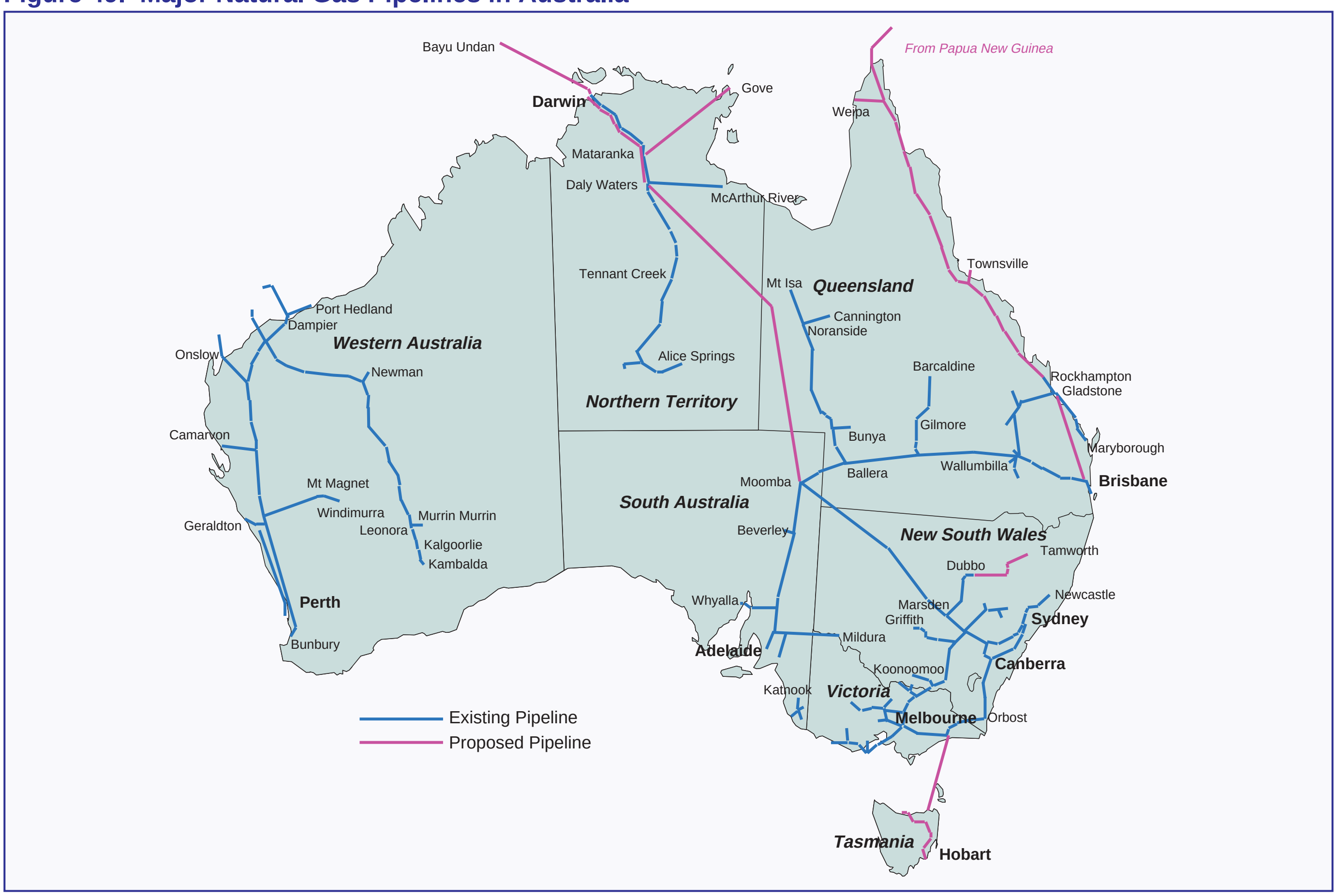
Figure 48. Natural Gas Consumption in Asia, 1980, 1999, and 2020



Note: Australasia includes Australia, New Zealand, and the U.S. Territories (Guam, Puerto Rico, and the U.S. Virgin Islands).

Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Figure 49. Major Natural Gas Pipelines in Australia



Source: Australian Gas Association, web site www.gas.asn.au/SECTN1.htm (May 2001).

[**44**]. The China National Offshore Oil Corporation (CNOOC) signed a preliminary agreement with Chevron to study the feasibility of acquiring an equity stake in the Gorgon fields. The Gorgon gas is one of the possible sources of LNG supply for CNOOC's Guangdong LNG import project [**45**].

Japan

Natural gas demand in Japan is projected to increase by 1.7 percent per year from 1999 to 2020 (Figure 48), well below the average of 2.4 percent per year for the industrialized countries as a whole and the 3.2 percent annual average projected for world growth in natural gas use. Japan's economy continues to languish, and slow-paced deregulation of the electric power and natural gas markets is causing uncertainty about future gas demand in Japan. This uncertainty, combined with the shutdown of Indonesia's Arun facility for 7 months in 2001 (see below), may be changing the normally rigid, long-term orientation of LNG markets in Japan. For example, Chubu Electric Power has signed a framework agreement with Malaysia's LNG Tiga for emergency supplies of LNG. No minimum or maximum volumes are specified, and Chubu is required to give only 10 days notice before lifting. The price will be determined when the transaction takes place [**46**]. In addition, Japanese trading houses are starting to look outside Japan to help commercialize otherwise stranded gas reserves. The financial backing of the Japanese trading firms could speed up the development of such reserves [**47**].

Developing Asia

Developing Asia is expected to contribute 19 percent of the increase in world gas demand from 1999 to 2020. The growth of 14.9 trillion cubic feet over the forecast period is slightly higher than that projected for North America. The region includes countries that are major producers of natural gas and LNG as well as rapidly expanding gas-consuming countries.

China

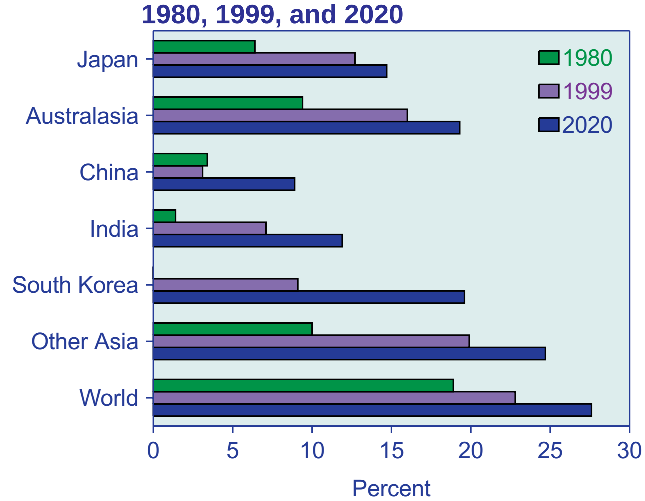
Natural gas provided 23 percent of world energy demand in 1999 but in China only 3 percent of energy demand was met by gas. Natural gas consumption in China is projected to increase by 10.1 percent per year from 1999 to 2020, raising the natural gas share of China's energy consumption to 9 percent by 2020 (Figure 50).

Environmental concerns in China are prompting movement toward gas and away from coal and oil, and energy security concerns are promoting the development of domestic gas supplies and the expansion of China's gas infrastructure. In early 2001, China's State Council approved a huge, $12 billion project to develop gas reserves in the remote western part of the country and move the gas east by pipeline to Shanghai and other Yangtze Delta cities [**48**] (see box on page 59). PetroChina completed the Sebei Lanzhou gas pipeline in September 2001, traversing a harsh natural environment. The pipeline has the capacity to move 141 billion cubic feet of gas annually from the Qaidam Basin to Lanzhou [**49**]. Supplying gas to Lanzhou has been a priority because it has the highest levels of sulfur dioxide and particulates in China and is considered one of the most polluted cities in the world [**50**].

In November 2001, PetroChina signed a contract to sell gas to the Wuhan municipal government. The gas is to be delivered through the proposed Zhong-Wu pipeline, using reserves from the Sichuan and Chongqing areas. The pipeline is expected to have an installed capacity of 3 billion cubic meters per year and provide gas to more than a dozen cities in the region. Wuhan agreed to a "take-or-pay" contract, with volumes increasing from 7 billion cubic feet in the first year to 42 billion cubic feet in the fifth year of operation. The central government is requiring PetroChina to enter take-or-pay contract deals with the cities along the pipeline route [**51**].

While China is promoting the expansion of domestic gas supplies, the development of an LNG import facility in Guangdong province is also proceeding. BP Amoco won the right to build the terminal but not necessarily the right to supply LNG to the facility. Both the Tangguh project in Irian Jaya, Indonesia, and the Greater Sunrise project in the Timor Gap are targeting the Guangdong

Figure 50. Natural Gas Share of Total Energy Consumption in Selected Asian Countries and the World, 1980, 1999, and 2020



Note: Australasia includes Australia, New Zealand, and the U.S. Territories (Guam, Puerto Rico, and the U.S. Virgin Islands).

Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

China's West-to-East Natural Gas Pipeline

Supplying natural gas to the industrial urban centers of eastern China, notably Shanghai, remains an important priority for the Chinese government. On March 25, 2000, China formally announced plans to build a massive cross-country pipeline that would transport natural gas from the Tarim basin in the west to Shanghai in the east. The pipeline would pass through seven provinces—Gansu, Ningxia, Shaanxi, Shanxi, Henan, Anhui, and Jiangsu—before reaching Shanghai. Construction of the 2,584-mile pipeline was originally slated to begin in September 2001 but has been postponed because contract negotiations between the government and the foreign companies that will be participating in the project have not been finalized.[a] The Chinese government still expects that the line will be completed before the end of 2003, but the date will depend largely on whether construction begins soon.

The West-to-East pipeline would initially deliver 424 billion cubic feet of natural gas per year to the eastern markets. Shanghai is scheduled to receive the major share, some 350 billion cubic feet per year, with the balance supplied to other provinces along the pipeline route (see map). The natural gas supplied is eventually to be increased to 706 billion cubic feet per year.[b] Thirty percent of total potential Chinese production capability of natural gas and 47 percent of the potential supply available to move between Chinese regions in 2010 is expected to originate in west China. These levels would justify the West-to-East gas pipeline, but China is also developing plans to import liquefied natural gas (LNG), as well as plans for other pipelines. The most prominent projects are the Guangzhou LNG project and the natural gas pipelines from Irkutsk in Siberia and Sakhalin in far eastern Russia.

(continued on page 60)

[a]M. Hurle, "Energy Sector Analysis: China: Mega Pipeline Facing Delays," *World Markets OnLine,* web site www.worldmarketsonline.com (October 9, 2001).

[b]Fesharaki Associates Consulting & Technical Services (FACTS), Inc., *China's Natural Gas to 2015* (Honolulu-Singapore, October 2000), p. 4-22.

China's West-to-East Natural Gas Pipeline (Continued)

The share of natural gas in China energy consumption is currently very low, estimated at 3 percent in 1999, compared with 10 percent in the rest of developing Asia and 23 percent in the rest of the world. China has been adding significant amounts of natural gas reserves over the past decade, and current reserves are estimates at 38.8 trillion cubic feet.[c] China considers an acceleration of natural gas production to be an attractive policy for switching to clean-burning fuels, both on environmental grounds and to tap domestic gas resources in substitution for domestic coal and imported oil. The *IEO2002* reference case forecast indicates that China's natural gas demand is expected to reach 2.8 trillion cubic feet by 2010 and 6.4 trillion cubic feet by 2020. A more optimistic, full-fledged fuel-switching policy could boost demand to 3.4 trillion cubic feet as early as 2010, with 53 percent going into power generation, 21 percent consumed in the chemical sector, and 25 percent used as city fuel.[d]

Although China sees the importance of developing domestic sources of natural gas in order to enhance the security of energy supplies, the cross-country pipeline is not necessarily economically sound, nor are its potential supplies currently needed to meet the low level of demand in eastern China. Environmental quality has been a significant concern behind the government's determination to implement the West-to-East project. Major cities in China frequently have been ranked high in various top 10 lists of the most polluted cities in the world. Decades of expansionary coal use have resulted in environmental degradation, which needs urgent remediation. Estimates by some independent observers and by Chinese officials put the direct economic losses caused by pollution at approximately $100 billion per year, and some analysts claim that China must now spend $20 billion per year just to prevent pollution from rising above current levels.[e]

For Shanghai, which is the target market for many large pipeline proposals, the high cost of supplying gas from western China largely reflects the cost of assembling gas from the various western supply basins (Tarim, Junggar, Turpan-Hami, and Qaidam) at a common point. From there, a large diameter pipeline could be used to connect with the Ordos basin and on to Shanghai. The delivery costs to Shanghai from west China gas would be much higher than the cost of importing Irkutsk gas from eastern Siberia. As a result, if the Chinese government were basing its decisions about constructing the West-to-East pipeline solely on the cost of transporting the gas to market, Chinese policy makers would choose Irkutsk over western China as the source of remote gas supply.[f]

While most of the natural gas industry in China continues to function under quotas and supply allocations, a parallel pricing regime has been created for all new foreign-invested projects. The new pricing structure attempts to create a mechanism to reflect the true economic cost of projects and an adequate gas transportation tariff to secure a profit margin for the developers. However, recent examples show that when the combination of the gas price and the pipeline tariff proposed by developers differs significantly from the maximum affordable citygate price, the Chinese gas regulators tend to adjust the total price by cutting the pipeline tariff. The Ordos-Beijing pipeline, owned by PetroChina and the Beijing city government, received approximately half its requested tariff (12.71 yuan, or $1.41, per cubic foot, versus a proposed 26.12 yuan, or $3.18); and the Zhongxian-Wuhan pipeline, partially financed by a foreign developer, was approved for a 9.53 yuan ($1.06) per cubic foot tariff despite a proposed tariff of 12.71 yuan per cubic foot. In both cases, the developers decided to proceed despite concerns that the pipeline project was not economically viable.[g]

Because of the project size and distance from market, the West-to-East gas pipeline project more nearly resembles import pipelines than those from domestic basins such as the Ordos and Sichuan, which serve the northeastern markets in and around Beijing. For example, the West-to-East China pipeline investment is larger than that required to supply a similar amount of gas from Sakhalin (far east Russia) and is nearly as large an investment as the Irkutsk (eastern Siberia) project and its giant Kovyktinsk field, which has double the supply capacity of west China fields.[h]

(continued on page 61)

[c]DRI-WEFA, "Energy Monitor: Asia," *World Energy Service Asia/Pacific Outlook* (Lexington, MA, October 2001).
[d]Lan Quan and Keun-Wook Paik, *China Natural Gas Report* (London, UK: Xinhua News Agency, Beijing and Royal Institute of International Affairs, 1998).
[e]Cambridge Energy Research Associates, *Onshore Gas Opportunities in China: A New Era?* (Cambridge, MA, February 2000), p. 3.
[f]Asia Pacific Energy Research Center, *Natural Gas Infrastructure Development: Northeast Asia, Costs and Benefits* (Tokyo, Japan, March 2000), p. 113.
[g]Cambridge Energy Research Associates, *Betwixt and Between: China's Natural Gas Industry under Commercial Principles* (Cambridge, MA, February 2001), p. 6.
[h]Asia Pacific Energy Research Center, *Natural Gas Infrastructure Development: Northeast Asia, Costs and Benefits* (Tokyo, Japan, March 2000), p. 111.

terminal. BP Amoco and the Indonesian state oil company, Pertamina, are promoting Tangguh; Royal Dutch / Shell is leading the Greater Sunrise project along with Woodside, Phillips, and Osaka Gas [***52***]. The Gorgon project in Australia is considered a long shot for supplying Guangdong, given technical problems related to its high carbon dioxide content [***53***].

In addition to the Guangdong facility, CNOOC signed an agreement with the Fujian provincial government to build a 2 million metric ton LNG receiving terminal. CNOOC would take responsibility for the terminal and an attached trunk pipeline, and the Fujian government would take care of the provincial distribution network. A detailed study must be done and submitted to the State Development Planning Commission for approval, but CNOOC would like to begin operation by 2005 or 2006 [***54***]. Fujian province is located on the south China coast between the LNG facility planned for Guangdong and the West-East pipeline that is intended to extend to Shanghai.

India

India has also been the target of intense interest by LNG producers as a country with great growth potential. Many projects have been proposed, but the collapse of the Dabhol project, uncertainties concerning LNG policies, and problems associated with selling costly gas to financially troubled state power distributors have slowed the advance of LNG import projects. Natural gas demand growth is projected to remain strong, however, and some projects are making progress.

China's West-to-East Natural Gas Pipeline (Continued)

Another issue of concern to the West-to-East pipeline developers is that China currently does not have an adequate distribution network to send massive natural gas supplies to individual users in Chinese cities, although progress is being made in improving the situation. In fact, because of the lack of distribution networks, many of the pipelines already completed are running at rates that are lower than their design capacity. For instance, the 536-mile Shaan-Jing pipeline connecting Jingbian in Shaanxi Province with Beijing, completed in September 1997, still is operating below capacity. Although the Shaan-Jing pipeline was designed to transport 194 million cubic feet per day, the initial delivery was only 106 million cubic feet per day. Even at that level, Beijing's actual gas consumption was much lower.

The 480-mile Yacheng-Hong Kong Pipeline, the longest undersea pipeline in Asia and the second largest in the world, was completed in 1996. It connects the offshore Yacheng 13-1 gas field with Hong Kong power plant at Black Point. The total cost of the pipeline was $1.1 billion. Because Hong Kong cannot consume all the gas delivered by contract, it must flare some of it under a "take-or-pay" clause. Other completed pipelines have encountered the same problem: extremely low utilization rates at the initial stage, because the target cities or industrial users were not ready.[i]

The future of natural gas in China's electricity generation sector—the largest targeted market for the West-to-East pipeline gas—is also uncertain. A number of factors could put the natural gas at a disadvantage relative to other fuels. One is that the power sector, without proper environmental regulations such as taxing heavy polluters, would not expand the use of natural gas for electricity generation. Coal would remain the preferred fuel because of its ability to compete on cost. Secondly, the retail price of natural gas in Shanghai would have to compete with cheaper imports of LNG. The latter may occur if the Guangzhou LNG project is deemed a success and another terminal is built near Shanghai.[j] Various governmental studies insist that the end-user prices of the pipeline gas will be competitive with LNG; however, the calculations are based largely on the assumption that pipeline utilization rates will be high. The cost will be much higher if the pipeline is underutilized.

To finance the West-to-East pipeline project, the Chinese government has announced that it would allow foreign investors to hold majority stakes in the pipeline, which will cost an estimated $4.8 billion to build. China will also open potentially lucrative areas of gas development and marketing to foreign companies, which will require an additional $13.2 billion in investment.[k] PetroChina, the official sponsor of the West-to-East project, short-listed a foreign consortium, which is led by ExxonMobil, Royal Dutch / Shell, and BP. However, BP decided to withdraw from the project in early September 2001, in the face of a demanding deadline to submit its final investment proposal. BP's withdrawal has underscored doubts that the 2,584-mile natural gas pipeline's commercial potential matches its political importance.

[i]Fesharaki Associates Consulting & Technical Services (FACTS), Inc., *China's Natural Gas to 2015* (Honolulu-Singapore, October 2000), p. 4-16.

[j]"Markets, Prizes, and Briefs," *Petroleum Intelligence Weekly*, Vol. 40, No. 24 (June 11, 2001), p. 11.

[k]"China: BP Pulls Out of the 4,000 km West-East Pipeline Project," *CEDIGAS NEWS REPORT*, Vol. 40, No. 38 (September 29, 2001), p. 7.

Enron's Dabhol project had collapsed long before the company itself (see box on page 135). The Maharashtra State Electricity Board accused Enron of overcharging and refused to pay for the power from Dabhol. The Enron-controlled Dabhol Power Company then defaulted on interest payments to international lenders on the gas-fired, 1,440 megawatt second phase of the project, which was 90 percent complete [***55***]. A 2.5 million ton LNG receiving terminal was said to be roughly 85 percent complete. Indian financial institutions are laying claim to the Enron assets, but their success at taking over the assets remains unclear [***56***].

A few LNG projects are making progress. National Thermal Power Corporation, India's biggest power producer, invited bids to supply 4 million tons per year of LNG to its proposed gas-fired power plants. Qatar, Oman, and Iran are considered frontrunners. A potential stumbling block, however, is the shortage of pipelines to move the gas to the relatively distant locations of the generating facilities. Petronet LNG, which is planning to begin importing gas at its 5 million ton LNG facility at Dahej in Gujarat in December 2003, is also preparing to select a contractor to build a 2.5 million ton per year terminal at Kochi in Southern India [***57***].

LNG policy confusion and backpedaling on market liberalization could complicate LNG projects. Policy differences among ministries are delaying the adoption of an integrated policy on importing, consuming, and transporting LNG. The government is considering a proposal to free natural gas prices along with oil prices in April 2002, but because of opposition by the Ministry of Finance, natural gas prices may be only partially freed. Another measure under consideration would require 26 percent Indian ownership in any venture shipping LNG to India, gradually rising to 50 percent in 5 years. In order to ensure domestic control, the government is also likely to insist on free-on-board (f.o.b.) contracts that obligate the buyer to arrange for transporting the product [***58***].

South Korea

Natural gas demand in South Korea is expected to grow by 6.6 percent per year from 1999 to 2020. Despite an economic slowdown, gas consumption jumped by about 13 percent in the first half of 2001. The surge in demand occurred in the residential and industrial sectors as well as power generation, reflecting a rapidly expanding gas grid. City gas demand is expected to remain strong as progress is made on a nationwide transmission system. The increase in gas demand came despite LNG prices that topped $5 per million Btu when oil prices were high. LNG prices are beginning to ease, but the responsiveness of gas demand to price was not evident in the first half of the year [***59***].

Other Developing Asia

Indonesia is the largest LNG producer in the world, but unrest in the province of Aceh resulted in the shutdown of the Arun LNG facility for 7 months in 2001. The shutdown left Korea Gas Corporation (Kogas) and Japan's Tohoku Electric searching for replacement supplies. Because South Korea's summer gas consumption is less than half of the winter level, Kogas was able to get by with an occasional cargo from Bontang to supplement its contracted supplies from the Middle East and Malaysia. Tohoku received several replacement cargoes from the Bontang facility and from Malaysia [***60***].

The Arun facility was commissioned in 1978 and was expected to reach the end of its producing life over the next decade or so due to declining gas reserves. Two trains were shut down in 2000 [***61***]. But the problems in Aceh may speed the scaling down of Arun. Two Japanese utilities indicated that they may cut imports from Arun from 3.5 million tons per year to 1 million tons per year when their 20-year contracts expire in 2005 [***62***].

Indonesia is planning to expand the LNG facility at Bontang and to build a new plant at Tangguh in Irian Jaya, but the instability could hurt the ability of these projects to secure buyers. Indonesian officials claimed that Japanese utilities and CPC Taiwan have committed to take over 3 million tons per year from Tangguh, but both CPC and the Japanese utilities denied any keen interest [***63***]. El Paso Natural Gas, a U.S. company, was seeking to secure LNG supplies from the Timor Gap, but with that project on hold El Paso is showing interest in Tangguh. An independent power project from the Philippines, GNPower, signed a letter of intent to buy 1.3 million tons per year from Tangguh even though the Malampaya fields just started to deliver gas onshore. Some sources expect the Malampaya gas to be more expensive than imported LNG [***64***].

Malaysia is expanding its Bintulu LNG facility without the long-term contracts in place that normally accompany an LNG project. The 6.8 million ton per year expansion will increase total capacity to 23 million metric tons per year, making Bintulu the largest LNG producing facility in the world. The project, which is being jointly developed by Petronas and Royal Dutch/Shell, had a letter of intent for 2.6 million tons per year from Enron's subsidiary in India, but that is highly unlikely at this point. That leaves a firm contract for only 0.9 million tons per year with Tohoku Electric. Malaysia is desperately seeking Japanese and South Korean customers to absorb the gas and could be a large contributor to the nascent LNG spot market [***65***].

While the Trans-ASEAN Gas Pipeline remains just a concept on paper, small pieces of what could eventually be a gas pipeline grid in Southeast Asia are being developed. In January 2001, gas began to flow from Indonesia's West Natuna fields to Singapore, and in February a contract was signed to bring gas to Singapore from Indonesia's South Sumatran fields. The contract calls for gas to begin flowing in July 2002 and continue for 20 years. In March, Indonesia signed a contract with Malaysia to supply 1.5 trillion cubic feet of gas over a 20-year period from the West Natuna fields into the Malaysian peninsular network [**66**].

Delays continue for a planned gas pipeline from the Thailand-Malaysia joint development area (JDA) to southern Thailand and on to northwest Malaysia. Villagers at the proposed landing point for the pipeline protested that it would inflict environment damage and affect fishing in the area. Thai authorities rejected the project's environmental impact assessment. The pipeline was to have been completed by mid-2002 but now is not expected until the end of 2003 at the earliest [**67**]. A connection to Thailand's offshore gas fields and transmission system to the north of the JDA is also being considered, which would allow gas to be delivered to Bangkok [**68**].

Myanmar gas can now reach demand centers along Thailand's main gas transmission line following the completion of a 60-mile pipeline connection from Ratchaburi to Wang Noi. This should allow Thailand to take all of the gas specified in its contract with Myanmar. The reduction in electricity and gas demand after the 1997 financial crisis left Thailand with more gas than could be used at the Ratchaburi generating plant.

The Philippines inaugurated the Malampaya gas-to-power project in October 2001 and unveiled plans for expanded natural gas use. The privatization plan of the state-owned power company, the National Power Corporation, is supposed to include the conversion of certain plants to gas-fired power. A pipeline is planned to transport gas from Batangas to Manila (the so-called Batman project) to switch a power plant that is currently burning diesel to natural gas. The Malampaya infrastructure currently has enough capacity to fuel up to 4 gigawatts of power generation capacity, and 2.7 gigawatts are under contract [**69**].

The new government of Prime Minister Begum Khaleda Zia in Bangladesh is considering a gas export pipeline to India, although opposition remains fierce. Economic realities are compelling the deliberation, especially given foreign exchange difficulties that have halted payments totaling $54 million each to Shell and Unocal for gas purchased over the past few months. Unocal indicated in its proposal for a 500 million cubic feet per day pipeline to Delhi that the Bangladeshi government could receive $3.7 billion in revenue over the next 20 years [**70**]. Demonstrations and street protests followed indications that the government was considering natural gas exports [**71**].

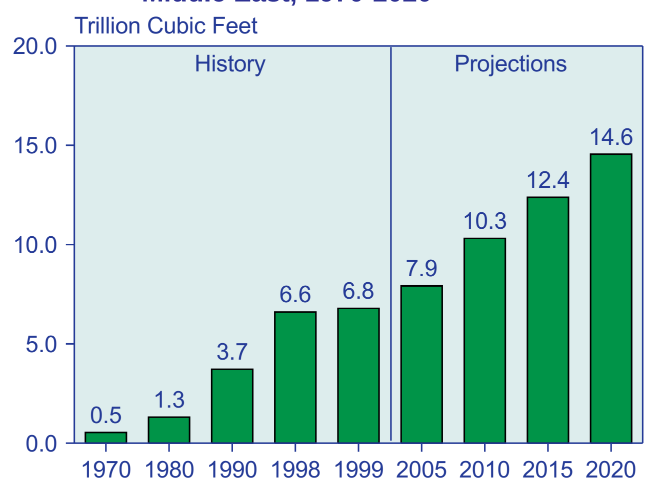
East Timor and Australia agreed to a 90/10 split of revenues from natural gas development in the Timor Gap. The original agreement, negotiated when East Timor was part of Indonesia, called for a 50/50 split of revenues [**72**]. The initial encouragement that the agreement gave to gas development in the region quickly dissipated when Phillips and its partners in the Bayu-Undan project indefinitely deferred development until certain legal, fiscal, and taxation issues arising from the new agreement are resolved [**73**].

Middle East

As of January 1, 2002, the Middle East's reserves of 1,975 trillion cubic feet were essentially equal to the FSU's 1,972 trillion cubic feet, but the region's production and consumption were less than one-third of those in the FSU. The Middle East more than doubled production between 1990 and 1999 and nearly doubled consumption. The region increasingly seeks to develop domestic gas markets, and rapid growth is expected in the *IEO2002* forecast (Figure 51). Consumption is projected to more than double, growing to 14.6 trillion cubic feet in 2020 from 6.8 trillion cubic feet in 1999, an average annual rate of 3.7 percent. The most significant reserves in the Middle East are held by (in order of size) Iran, Qatar, Saudi Arabia, and the United Arab Emirates (UAE), each holding in excess of 200 trillion cubic feet.

Because the bulk of Iranian natural gas reserves are located in nonassociated fields and have not been

Figure 51. Natural Gas Consumption in the Middle East, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

developed, Iran has tremendous potential for expansion of both its internal and export natural gas markets. Additionally, with much territory yet to be explored, Iran continues to make significant new discoveries. Most of Iran's reserves are in the southern part of the country, and Iran imports natural gas from Turkmenistan to satisfy demand in the northern part of the country. The country is also looking into the possibility of importing from Azerbaijan. Currently, Iran imports relatively small amounts of its gas, about 4 percent of its total natural gas consumption. Natural gas accounts for approximately 44 percent of Iran's total energy consumption, but the government plans to invest billions of dollars in the gas sector during its current Five-Year Development Plan, hoping to advance both its domestic and its export markets.

Over the past year or so, Iran has made a number of significant gas finds, though none that come close in magnitude to its South Pars field. South Pars is Iran's largest nonassociated natural gas field, projected to begin production in 2002. It is estimated to contain approximately 280 trillion cubic feet of gas, much of which is considered to be recoverable, and more than 17 billion barrels of liquids. South Pars is geologically an extension of Qatar's 241 trillion cubic feet North Field. Gas from South Pars is slated to be shipped north via the planned IGAT-3 pipeline, and possibly an additional IGAT-4 line, and then reinjected to boost oil output in mature fields that are currently in decline.

Iran's South Pars gas could also be exported, both by pipeline and possibly by tanker as LNG. In addition to the 280 trillion cubic feet in the South Pars field, a separate North Pars field contains an additional 48 trillion cubic feet. TotalFinaElf, Russia's Gazprom, and Malaysia's Petronas have jointly agreed to explore South Pars and to help develop the field during Phase 2 and 3 of its development. Phase 1, which is being handled by Petropars, has been delayed several times and now is scheduled for partial completion by the end of 2002. The development is expected to proceed through 12 phases, with phases 9 and 10 expected to supply the domestic market and phases 11 and 12 slated for LNG export [***74***].

Iran has reportedly discussed natural gas exports with Kuwait and the United Arab Emirates. To date, it has provided exports only to Turkey. In 1996, Iran agreed to supply Turkey with natural gas for a period of 22 years. Originally slated to commence in 1999 at a rate of 300 million cubic feet per day and increase to a level of 1 billion cubic feet per day in 2005, the flow of gas from the northwestern Iranian city of Tabriz to Ankara was postponed until September 2001 after Turkey requested a delay due to economic problems that prohibited it from completing its portion of the pipeline. A further delay came when Turkey maintained that a metering station on the Iranian side was not ready for operation. Flows finally began on December 11, 2001.

Turkey's growth in natural gas consumption is proceeding at a much more rapid rate than its growth in production, and the country is expected to increase its imports from neighboring countries significantly. Currently Turkey is supplied by only Russia and Africa. Russian pipeline imports account for approximately 70 percent of Turkey's imports, with additional new pipeline supplies from Iran and LNG from Algeria and Nigeria accounting for the rest of its gas supply. Although it has had many recent gas finds, most of Turkey's gas is reinjected to enhance oil recovery, and domestic production is not expected to contribute significantly to internal consumption.

Across the border from Iran's South Pars is Qatar's North Field, the largest nonassociated gas field in the world. Internal consumption in Qatar declined by slightly over 9 percent in 2000, but its 2000 production exceeded 1999 production by 20 percent. The additional production was primarily to serve Qatar's rapidly growing export market. Almost half of Qatar's production was exported in 2000, all in the form of LNG. In 2000, Qatar was the fourth largest exporter of LNG in the world, behind Indonesia, Algeria, and Malaysia. Its major customers were Japan and South Korea, but the United States, Spain, Italy, and France also received cargos from Qatar. Investment in LNG liquefaction facilities in Qatar has been significant. The first facility was completed in 1997, with three trains and a capacity of 7.7 million metric tons per year, and the second was completed in 1999, with two trains and a capacity of 6.6 million metric tons per year. There are plans to expand the second facility by 8.9 million metric tons per year by adding two additional trains.

Qatar is expected to play a major role in increasing natural gas use in the Middle East. According to current plans, gas will be exported by a new pipeline from Qatar's North Dome field to Abu Dhabi, Dubai, and Oman, with a possible future link to India. The planned pipeline, to be developed by Qatar's Dolphin Energy, Ltd. (DEL), will be the first cross-border pipeline in the Middle East. According to a Dolphin Energy press release on January 7, 2002, "the Dolphin project will complement the gas operations of Abu Dhabi National Oil Company (ADNOC) and meet demand for gas in the UAE, especially from the power generation sector, which is rising by between 10-12 percent a year" [***75***]. This will supplement Abu Dhabi's own production, which is not expected to increase as rapidly as its consumption, despite its plentiful natural gas resources. The pipeline will also provide opportunities to develop new industries in both Qatar and the UAE. Dolphin expects deliveries to its customers in the UAE to begin in

2005. If its projection of delivering 3 billion cubic feet per day is met, it would account for close to 10 percent of the world's pipeline trade.

The UAE contains extensive gas reserves, over 90 percent of which are in Abu Dhabi. LNG has been exported from Abu Dhabi's Das Island facility since 1977. The facility was expanded in 1994 and now consists of three trains with a total capacity of 3.3 million metric tons per year. Japan is the primary customer for Abu Dhabi's LNG exports. In May 2001 a pipeline from Abu Dhabi to Dubai (Abu Dhabi and Dubai are the two largest Emirates) began operating, supplementing Dubai's natural gas supply. Before May, Dubai was served entirely by Sharjah, another of the Emirates. UAE is intent on expanding its natural gas market and has invested heavily in moving to natural-gas-fired power plants and industry. It is also a partner in the Dolphin project to deliver gas from Qatar to the UAE, Oman, and potentially India.

Approximately two-thirds of Saudi Arabia's currently proven gas reserves consist of associated gas. Before 1984, when Saudi Arabia's Master Gas System (MGS) was completed to deliver gas to the industrial cities of Yanbu and Jubail, all of Saudi Arabia's natural gas was flared. While Saudi Arabia's gas sector has not shown significant growth in recent years, demand increases are anticipated, and Saudi Arabia has been promoting foreign investment in its gas sector. In May 2001, Saudi Arabia selected companies to participate in a $25 billion "Saudi Gas Initiative," the first major reopening of Saudi Arabia's upstream hydrocarbons sector to foreign investment since nationalization in the 1970s. The purpose of the initiative, which consists of three "core ventures," is to integrate upstream gas development with downstream petrochemicals and power generation. Companies selected for the three core ventures under the Gas Initiative are (1) South Ghawar: ExxonMobil, Shell, BP, Phillips; (2) Red Sea: Exxon plus an Enron / Occidental partnership; and (3) Shaybah: Shell, Total, Conoco.

Core Venture 1 will include exploration, pipelines, two gas-fired power plants, two petrochemical plants, and two desalination units. Core Venture 2 will involve exploration and development in and along the coast of the Red Sea in northwestern Saudi Arabia and the construction of a petrochemical plant and a power station. Core Venture 3 will involve exploration near Shaybah in the Rub al-Khali ("Empty Quarter") of southeastern Saudi Arabia, development of the Kidan gas field, laying of pipelines from Shaybah to the Haradh and Hawiyah gas treatment plants east of Riyadh, and construction of a petrochemical plant in Jubail. Additional gas use is being encouraged for the country's growing petrochemical industry, for electricity generation, for desalination plants and other industrial facilities, and as a replacement for oil burning. The use of gas instead of oil domestically is intended to help free up additional crude oil for export.

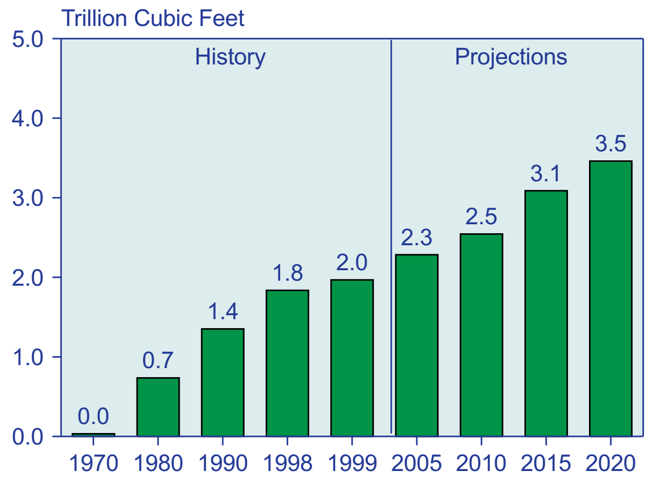
Africa

Africa's gas reserves, estimated at 394 trillion cubic feet, account for 7.4 percent of global reserves. Algeria and Nigeria account for 284 trillion cubic feet of reserves, or 72 percent of the total. Egypt and Libya account for another 21 percent, with the remainder of Africa containing only 7 percent of the continent's total reserves. Thus, gas exploration and production activities, along with export projects and plans to increase domestic use, are concentrated in north and west Africa.

Africa accounts for about 5 percent of the world's natural gas production but only 2 percent of the world's consumption. In 2000, Africa provided 17.4 percent of the world's natural gas exports, including 9.1 percent of pipeline exports and 41.0 percent of LNG exports [***76***]. Two-thirds of the total exports came from Algeria. Africa's natural gas consumption is increasing significantly, and the *IEO2002* reference case projects average increases of 7.4 percent per year, from 2.0 trillion cubic feet in 1999 to 3.5 trillion cubic feet in 2020 (Figure 52).

In Nigeria, increased associated gas production has developed as a result of increased crude oil production and intensified efforts to reduce gas flaring. Gas is liquefied at the Bonny Island facility, which has been in operation since 1999, and shipped to markets that include the United States, Spain, Italy, France, and Turkey. Two trains are currently operational with a combined

Figure 52. Natural Gas Consumption in Africa, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

capacity of 5.9 million metric tons per year. A third train, scheduled to come online in 2002, will provide another 2.95 million metric tons per year. A third expansion, proposed to come online in 2005/2006, will, if built, add two trains and an additional capacity of 8.0 million metric tons per year [***77***]. In 2000, Nigeria accounted for approximately 10 percent of Africa's LNG exports, and its exports are expected to grow as the Bonny Island facility expands.

Algeria is the continent's most developed export market, with 40 percent of its production being exported by pipeline to Italy, Spain, Portugal, Slovenia, and Tunisia and 37 percent exported as LNG to France, Belgium, Spain, Turkey, Italy, the United States, and Greece. The strong LNG market that has developed in Africa includes, in addition to Algeria and Nigeria, one operational facility in Libya, one facility under construction in Egypt and two proposed, and a proposed facility south of Nigeria in Angola [***78***]. Africa currently has 12 trains operational, with a combined capacity of 13.5 million metric tons per year. Three additional trains under construction will add another 11.8 million metric tons per year. Although Libya was the first to export LNG, beginning in 1970, Algeria was not far behind, opening its first facility in 1972. Nigeria entered the market in 1999 with the completion of its Bonny Island facility, and Egypt plans to enter in 2004 with its Damietta facility. Algeria has proposed locating another facility along the Mediterranean coast.

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